08-059-00701

Leyden Historical Activity

Year	Reported L&U	Turbine Fuel	Blown Gas
1963			
1964			
1965	150,000		
1966			
1967			
1968			
1969			
1970			
1971	345,000		
1972			
1973	122,880		
1974	106,043		
1975	98,577		
1976	19,667		
1977	132,568		
1978	130,404		
1979	130,404		
1980	155,530		
1981	66,616		
1982	131,089		
1983			
1984	-50,000		
1985			
1986	58,400		
1987			
1988	22,000		
1989		14987	170
1990	570,000	25072	361
1991	170,000	17380	190
1992	120,000	11282	119
1993	90,000	13777	102
1994	85,000	9025	216
1995	65,000	18021	364
1996		26978	510
1997		29648	661
1998		21104	327
1999	150,000	21081	295
2000		26411	491
2001		21380	102
2002*		22980	349
TOTAL	**2,869,178**	**279126**	**4,257**

* Through October 31, 2002

LEYDEN L E U

1960 THRU 1979 FILE A

FORM 000-22-0000 INTER-DEPARTMENT MEMO — PUBLIC SERVICE COMPANY OF COLORADO

DATE December 26, 1979

TO Mr. Nick Brenner, Supervisor — Chart Processing (DEPARTMENT OR DIVISION)

FROM Mr. John A. Shealy, Special Projects Engineer — Fuel Supply Development (DEPARTMENT OR DIVISION)

ATTN.

SUBJ. Lost and Unaccounted For Gas for 1979

Please revise your next summary of Gas Delivered Report to include 155,530 MCF to be written off as Lost and Unaccounted For Gas. @ 14.65

Also, Please change cushion gas from 537,000 MCF @ 14.65 # to 536,682 MCF @ 14.65 #.

I will keep in contact with you regarding our "new" discovered error. But for the time being, please continue your reporting procedures.

John A. Shealy

John A. Shealy

JAS:su

PSC 039500

FORM 030-22-0035 **INTER-DEPARTMENT MEMO – PUBLIC SERVICE COMPANY OF COLORADO**

DATE November 14, 1979

TO Mr. Nicholas Brenner, Supvr. Gas Chart Processing — WSGCo. (DEPARTMENT OR DIVISION)

FROM John A. Shealy, Special Projects Engineer — Fuel Supply Development (DEPARTMENT OR DIVISION)

ATTN.

SUBJ. Volume Changes at the Leyden Storage Project

Please make the following changes in your "Summary of Gas Delivered" Reports regarding cushion volume and maximum working volume at the Leyden Storage facilities:

	534 297
Cushion Gas	537 MMCF @ 14.65#
	636 MMCF @ 12.37#
Maximum Working Volume	1700 MMCF @ 14.65#
	2013 MMCF @ 12.37#

If you have any questions, please contact me on 7416.

John A. Shealy

John A. Shealy

JAS:cp

8.4667 m^2CF/DAY ⇒

IF THE CAUSHEN IS HELD AT

226 PSIG DURING THE HEATING SEASON

THEN EXPECT:

190 m^2CFD FOR 4.5 DAYS.

OR.

195 m^2CFD FOR 4.3 DAYS

OR

200 m^2CFD FOR 4 DAYS

OR

205 m^2CFD FOR 3.8 DAYS.

OR

185 m^2CFD FOR 4.8 DAYS

OR

180 m^2CFD FOR 5 DAYS

LEEROY BROWN

196 DURING 77-78

HISTORICAL MAXIMUM

190 m^2CFD

226 → 217 FREEFLOW

PSC 039502

FORM 850-22-0058 INTER-DEPARTMENT MEMO — PUBLIC SERVICE COMPANY OF COLORADO

DATE December 31, 1979

TO Mr. O. D. Davis, Property Accounting Director — DEPARTMENT OR DIVISION

FROM R. R. Midwinter, Controller — DEPARTMENT OR DIVISION

ATTN.

SUBJ. Change in Volume of Cushion Gas at Leyden

Mr. Lynn Wilkinson has advised me that the design of the Leyden Underground Gas Storage facility was modified prior to 1979 from 100 pounds depletion pressure to 60 pounds depletion pressure. Accordingly, more gas is now recoverable from the storage facility and the corresponding reduction in the volume of Cushion Gas should be recognized.

Per my discussion with Mr. Wilkinson last week, the amount of "Cushion Gas" should be reduced from 834,000 MCF to 537,000 MCF.

Please set up the necessary entries to reflect the reduction in Cushion Gas. Also record the salvage value of the reclassified gas as an addition to account number 81-164-11, Gas Stored Underground - Current, at its value for tax purposes to avoid creating an insignificant book-tax difference in the Inventory Account. (The Cushion Gas is being depreciated for book purposes whereas it is being amortized for tax purposes)

R R Midwinter

RRM/c
cc: D. D. Brunkhardt
Lynn Wilkinson
F. W. Beier

PSC 039504

STUDY OF LEYDEN ACTIVITY From November 1, 1978 - October 31, 1979

(This period was chosen because it uses the most currently known data)

FACTS: The dead weight shut in pressure for November 1, 1978 was 247.9 psig (Management Report). The dead weight shut in pressure for October 31, 1979 was 241.2 psig (per Ray Engebrit, Supt. Leyden Gas Storage). Since the premise of this study is that like pressures equals like volumes over any period of time the two known pressure must be adjusted to a common value by either injecting or withdrawing gas in accordance with the cavern pressure-volume curve. (See Corrections in Following Table).

MCF @ 14.65 psia

DATE	INFORMATION SOURCE	(+) INJECTION	(-) WITHDRAWAL	* NET ACTIVITY
Adjust Beginning Pressure From 247.9 To ~~250~~ psig 241.2 (11.625?)	Cavern Pressure-Volume Curve	~~18,784~~	77,893 -0-	+18,784
November 1978	ACTUALS	477,218	409,599	+67,619
December 1978	ACTUALS	677,579	1,193,606	-516,027
January 1979	ACTUALS	550,747	669,617	-118,870
February 1979	ACTUALS	893,229	222,492	+670,737
March 1979	ACTUALS	5,512	-0-	+5,512
April 1979	ACTUALS	1,635	982,234	-980,599
May 1979	ACTUALS	-0-	351,673	-351,673
June 1979	ACTUALS	-0-	-0-	-0-
July 1979	ACTUALS	-0-	-0-	-0-
August 1979	ACTUALS	610,935	-0-	+610,935
September 1979	ACTUALS	698,012	-0-	+698,012
October 1979	ACTUALS	69,581	41,642	+27,939
~~Adjusted~~ Ending Pressure ~~From~~ 241.2 ~~To 250~~ Psig	Cavern Pressure-Volume Curve	~~78,713~~ 3,984,448	-0- 3,948,756	~~+78,713~~ -55,552**
TOTAL	-------	4,081,945	3,870,863	+155,530

L & U = 155,530 MCF @ 14.65 psia = 184,196 MCF @ 12.37 psia

Total Leyden Volume (Working plus Cushion Gas) = 2,236,175 MCF @ 250 psig

Total Gas Activity = 4,081,945 + 3,870,863 = 7,952,808 MCF

% L & U (of Total Leyden Volume) = $\frac{155,530}{2,236,175}$ = 6.96%

191,477

% L & U (of Total Activity) = $\frac{155,530}{7,952,808}$ = 1.95%

" Hughes-S[illegible]

(*) NOTE: Net Activity = Injection - Withdrawal

(**) NOTE: Due to increase in Total Volume
(L & U calculated as 211,082 MCF, However, due to Volume change, Actual L & U = 155,530 MCF).

NOVEMBER 1, 1979

CAVERN PRESSURE = 241.7 psig

TOTAL GAS IN STORAGE = 2,599,287 MCF

241.7 (11.6258) = 2,809,955 MCF.

TOTAL INJECTION = 1,995,548 MCF

TOTAL WITHDRAWAL = 1,672,574 MCF

OCTOBER 31, 1980

CAVERN PRESSURE = 247.3 psig

TOTAL GAS IN STORAGE = 2,922,261 MCF

247.3 psig (11.6258) = 2,875,060 MCF

L+U = ACTUAL − THEORETICAL =

2,922,261 − 2,875,060 = $\boxed{47,201 \text{ mcf}}$

9/1/14

SEPT

PSC 039506

AVERAGE L+U CALCULATIONS.

NOVEMBER 1, 1979

CAVERN PRESSURE 241.7

	INJECTIONS	WITHDRAWALS
11/1 → 11/30	271,306	692,621
12/1 → 12/31	843,305	286,286
1/1 → 1/31	75,473	611,540
2/1 → 2/29	595,582	35,148
3/1 → 3/31	99,705	42,802
4/1 → 4/30	—	2,042
5/1 → 5/31	—	—
6/1 → 6/30	—	—
7/1 → 7/31	—	—
8/1 → 8/31	4,379	—
9/1 → 9/30	105,798	—
10/1 → 10/31	—	2,135 (BLOWN TO ATMOS.)

CAVERN PRESSURE ON OCTOBER 31, 1980 - 247.3

ANNUAL L+V CALCULATIONS.

NOVEMBER 1, 1979.
CAVERN PRESSURE = 241.7 PSIG.

10/20/80 → 10/31/80

36,185,580 GALLONS @ 14.65

$\times$ 7.69 $\frac{ft^3}{GALLONS}$ =

1 gallon = .13368 ft^3

4837261.6 ft^3 = 4,837.26 MCF @ 14.65

4,837.26 $\times$ = 84,412.6 MCF @ 14.65

METHOD I

NOVEMBER 1, 1979
CAVERN PRESSURE = 241.7 psig
ADJUSTED TO 247.3 psig (x 11.6258)

	+ (INJECTIONS)	− (WITHDRAWALS)	(NET ACTIVITY)
		65,104	−65,104
11/1/79 → 11/30/79	271,306	692,621	−421,315
11/1/79 → 12/31/79	843,305	286,286	+557,019
1/1/80 → 1/31/80	75,473	611,540	−536,067
1/1/80 → 2/29/80	595,582	35,148	+560,434
1/1/80 → 3/31/80	99,705	42,802	+56,903
1/1/80 → 4/30/80	—	2,042	−2,042
1/1/80 → 5/31/80	—	—	
1/1/80 → 6/30/80	—	—	
1/1/80 → 7/31/80	—	—	
1/1/80 → 8/31/80	4,379	—	+4,379
1/1/80 → 9/30/80	105,798	—	+105,798
1/1/80 → 10/31/80	—	2,135	−2,135
OCTOBER 31, 1980	1,995,548	1,737,678	+257,870 MCF

CAVERN PRESSURE = 247.3 psig

LHH ZK

OF GALLONS H_2O WITHDRAWN
FROM 11/1/79 → 10/31/80 37,045,480 GALLONS
= 4,952.3 MCF @ 14.65 psia
= 86,082 MCF @ 240.0 psig

LCU = 257,870 MCF − 86,082
= 171,788 MCF

PSC 039509

METHOD II

- CAVERN PRESSURE ON OCT 31, 1980 IS 247.3 psig.
- THE CAVERN WAS SHUT IN ON MARCH 27, 1980 AT A CAVERN PRESSURE OF 249.6 psig. FROM MARCH 27, 1980 TO SEPTEMBER 15, 1980 THE CAVERN PRESSURE STABILIZED AT 239.7 psig, FROM SEPTEMBER 15, 1980 TO SEPTEMBER 31, 1980 APPROXIMATELY 105,798 MCF WAS INJECTED TO BRING CAVERN PRESSURE BACK TO 250.0 psig ON OCTOBER 1, 1980. FROM OCTOBER 1, 1980 TO OCTOBER 31, 1980 THE CAVERN PRESSURE DROPPED TO 247.3 psig. IF WE ASSUME THAT THIS PRESSURE WILL EVENTUALLY STABILIZE AT APPROXIMATELY 244.5 psig ... →

$$244.5 \text{ psig} \times 11.6258 \text{ M}^2\text{CF}/\text{psig} = 2,842,508 \text{ MCF}$$

CHART PROCESSING SHOWS A TOTAL IN STORAGE OF APPROXIMATELY ~ 2,922,261 MCF

$$2,922,261 \text{ MCF} - 2,842,508 = 79,753 \text{ MCF}$$

$$PV = (11.6259 \text{ M}^2\text{CF}/\text{psi})\ 250$$

$$= 2.8 \text{ BCF}$$

PSC 039510

L+U CALCULATED VOLUMES

FROM 8/20/79 → 9/14/80 L+U = 66,616 MCF ✓

FROM 8/20/79 → 10/31/80 L+U = 81,885 MCF ✓

FROM 11/1/79 → 9/14/80 L+U = 242,562 MCF

FROM 11/1/79 → 10/31/80 L+U = 259,953 MCF

FROM 8/20/79 → 11/1/79 L+U = -175,984 MCF

∴ FROM 8/20/79 → 11/1/80

L+U = 81,885 - 259,953 = -178,068 MCF

OR

L+U = 66,616 - 242,562 = -175,946 MCF.

AVG. -177,007 MCF.

∴ FROM 9/14/80 → 10/31/80

L+U = 259,953 - 242,562 = 17,391 MCF

OR

L+U = 81,885 - 66,616 = 15,269 MCF

AVG. 16,330 MCF

∴ FOR 11/1 → 10/31/80

PSC 039511

= (8/20/79 → 10/31/80) - (8/20/79 → 11/1/80) -

81,885 - (-177,007) = 258,892 MCF.

From 8/20/79 → 10/31/80 L+U = 81,885 MCF.

From 11/1/79 → 10/31/80; L+U = 259,953 MCF

From 8/20/79 → 9/14/80 L+U = 66,616 MCF

From 11/1/79 → 9/14/80 L+U = 242,562 MCF

∴ From 9/14/80 → 10/31/80

L+U = 259,953 MCF − 242,562 MCF

L+U = 17,391 MCF

∴ From 8/20/79 → 11/1/79

L+U = 66,616 − 242,562

L+U = −175,946

Summary

L+U Calculated from Stabilized Crown Pressures		L+U Actually Reported to Accounting Dept.
72 → 73	0 MCF	145,500 MCF
73 → 74	163,789 MCF	125,587 MCF
74 → 75	84,454 MCF	116,746 MCF
75 → 76	90,037 MCF	23,292 MCF
76 → 77	195,035 MCF	132,568 MCF
77 → 78	151,467 MCF	130,404 MCF
78 → 79	152,799 MCF	155,530 MCF
Total	837,583 MCF	829,627 MCF

ON 9/14/72 STABILIZED CAVERN PRESSURE = 132.5 PSIG

ON 9/1/73 STABILIZED CAVERN PRESSURE = 174.7 PSIG

INJECTIONS FROM 9/14/72 → 9/1/73 = 2,774,452 MCF
WITHDRAWALS FROM 9/14/72 → 9/1/73 = 2,351,058 MCF

$L+U = (2,774,452 - 2,351,058)_{MCF} - (174.7 - 132.5)_{PSIG}\left(11625.8 \frac{MCF}{PSIG}\right)$

$72 \Rightarrow 73$ $L+U$ = $-67,214$ MCF

ACTUAL REPORTED $72 \Rightarrow 73$ $L+U$ = 145,500 MCF

ON 9/1/73 STABILIZED CAVERN PRESSURE = 174.7 PSIG

ON 8/28/74 STABILIZED CAVERN PRESSURE = 120.0 PSIG

INJECTIONS FROM 9/1/73 → 8/28/74 = 1,896,281 MCF
WITHDRAWALS FROM 9/1/73 → 8/28/74 = 2,368,423 MCF

$\therefore L+U = (1,896,281 - 2,368,423) - (120.0 - 174.7)_{PSIG}\left(11625.8 \frac{MCF}{PSI}\right)$

$73 \Rightarrow 74$ $L+U$ = 163,789 MCF

ACTUAL REPORTED $73 \Rightarrow 74$ $L+U$ = 125,587 MCF

ON 8/28/74 STABILIZED CAVERN PRESSURE = 120.0 psig

ON 8/1/75 STABILIZED CAVERN PRESSURE = 123.7 psig.

INJECTIONS FROM 8/28/74 → 8/1/75 = 2,718,308 MCF
WITHDRAWAL FROM 8/28/74 → 8/1/75 = 2,590,838 MCF

$L+U = (2{,}718{,}308 - 2{,}590{,}838)\,\text{MCF} - (123.7 - 120)\,\text{psig}\left(11625.8\ \frac{\text{MCF}}{\text{psig}}\right)$

74 → 75 L+U = 84,454 MCF

ACTUAL REPORTED 74→75 L+U = 116,746 MCF.

ON 8/1/75 STABILIZED CAVERN PRESSURE = 123.7 psig
ON 8/31/76 STABILIZED CAVERN PRESSURE = 110.2 psig

INJECTIONS FROM 8/1/75 → 8/31/76 = 2,818,700 MCF
WITHDRAWALS FROM 8/1/75 → 8/31/76 = 2,885,611 MCF

$L+U = (2{,}818{,}700 - 2{,}885{,}611)\,\text{MCF} - (110.2 - 123.7\,\text{psig})\left(11{,}625.8\ \frac{\text{MCF}}{\text{psig}}\right)$

75 → 76 L+U = 90,037 MCF

ACTUAL REPORT 75→76 L+U = 23,292

ON 8/31/76 STABILIZED CAVERN PRESSURE = 123.7 psig
ON 8/30/77 STABILIZED CAVERN PRESSURE = 113.9 psig

INJECTIONS FROM 8/31/76 → 8/30/77 = 2,657,929 MCF
WITHDRAWALS FROM 8/31/76 → 8/30/77 = 2,578,827 MCF

$L\&U = (2{,}657{,}929 - 2{,}578{,}827)\,\text{mcf} - (113.9 - 123.7\,\text{psig})\left(11625.8\,\frac{\text{mcf}}{\text{psig}}\right)$

76 → 77 L+U = <u>195,035 MCF</u>

ACTUAL REPORTED 76 → 77 L&U = <u>132,568 MCF</u>

ON 8/30/77 STABILIZED CAVERN PRESSURE = 113.9 psig
ON 9/8/78 STABILIZED CAVERN PRESSURE = 122.0 psig

INJECTIONS FROM 8/30/77 → 9/8/78 = 3,328,592 MCF
WITHDRAWALS FROM 8/30/77 → 9/8/78 = 3,082,954 MCF

$L\&U = (3{,}328{,}592 - 3082{,}954) - (122.0 - 113.9\,\text{psig})\left(11625.8\,\frac{\text{mcf}}{\text{psig}}\right)$

77 → 78 L+U = <u>151,469 MCF</u>

ACTUAL REPORTED 77 → 78 L&U = <u>130,404 MCF</u>

ON 9/8/78 STABILIZED CAVERN PRESSURE = 122.0 psig
ON 8/20/79 STABILIZED CAVERN PRESSURE = 111.7 psig

INJECTIONS FROM 9/8/78 → 8/20/79 = 3,862,275 MCF
WITHDRAWALS FROM 9/8/78 → 8/20/79 = 3,829,221 MCF

$L+U = (3,862,275 - 3,829,221)\,\text{mcf} - (111.7 - 122\,\text{psig})\left(11625.8\,\frac{\text{mcf}}{\text{psig}}\right)$

78 → 79 L+U = 152,799

ACTUAL REPORTED 78 → 79 L+U = 155,580 MCF.

PSC 039519

FROM 9/29/78 TO 10/30/78

CAVERN PRESSURE WENT FROM

254.8 psig (9/29/78) TO 246.5 psig (10/30/78)

WITH A NET INJECTION OF. 99601 MCF

WE WENT FROM 254.8 psig TO 246.5 psig
WITH A NET INJECTION OF 99,601 MCF @ 14.65.

WE DROPPED 8.3 psig WITH 99,601 MCF INJECTED.
THIS SHOWS UP ON AN L+U CALCULATION. AS
AN. (8.3 x 8.9447 m²cf) + 99601 = 173,842 MCF ERROR

FOR YEARLY L+U CALCULATION:

YOU MUST HAVE GOOD STABLE BEGINNING AND
ENDING PERIODS OR PRESSURES AND THEN PORTION
IT OUT FOR ACCOUNTING PERIODS.

exmp.

$\left(\dfrac{\text{GOOD L+U OVER 2 YEARS}}{\text{24 MONTHS}} \times \dfrac{\text{12 MONTHS}}{} \right.$

PSC 039520

ON NOVEMBER 1, 1978
CAVERN PRESSURE = 247.9 psig.
9/8/78 CAVERN PRESSURE = 122.0 psig.

FROM 9/8/78 TO 9/30/78 - 1,171,073 MCF OF GAS @ 14.65 WAS INJECTED INTO LEYDEN.

ON 9/29/78 CAVERN PRESSURE = 254.8 psig.

ON 10/9/78 CAVERN PRESSURE HAD DROPPED TO 246.3 psig. WITH NO WITHDRAWALS OUT OF THE CAVERN.

FROM 10/9/78 TO 10/13/78 - 30,715 MCF INJECTED.

ON 10/13/78 CAVERN PRESSURE - 247.0 psig

ON 10/16/78 CAVERN PRESSURE - 245.9 psig.
ON 10/16/78 19,878 MCF WAS INJECTED
ON 10/17/78 CAVERN PRESSURE - 248.8 psig.
ON 10/17/78 10,019 MCF WAS INJECTED.

FROM 10/18/78 TO 10/25/78. THE CAVERN PRESSURE DROPPED FROM 249.0 psig TO 246.0 psig.
(3 psig IN 7 DAYS)

PSC 039521

OR. 5/1/78 - 92.4. ?

ON 9/8/78. - 122 psig

8/20/79 - 111.7 psig

FROM 9/8/78 → 8/20/79.

INJECTIONS = 3,862,275 MCF
WITHDRAWALS = 3,829,221 MCF

DIFFERENCE
NET INJECTION OF - 33054 MCF

(8.9447) + 10.3 psig

= 125,184

OR A 19.3 psig INCREASE

PSC 039522

+ L&U
(. ADDITIONAL

NOV 1, 1979 → NOVEMBER 30, 1979.

NOV 1, 1979 CAVERN PRESSURE = 241.7

NOV 30, 1979 CAVERN PRESSURE = 183.6.

NET WITHDRAWAL OF 421,315 MCF.

CAVERN PRESSURE DROPPED APPROXIMATELY 58.1 PSIG

@ 8.9447 MCF/PSIG

NET WITHDRAWAL SHOULD BE EQUAL TO. 519,687 MCF.

ONLY 421,315 MCF WAS WITHDRAWN

THEREFORE WE HAVE A

S-L+U OF

+ 98,372. MCF @ 14.65

PSC 039523

DECEMBER 1, 1979 → DECEMBER 31, 1980.

DEC. 1, 1979 CAVERN PRESSURE EQUAL TO - 176.2 psig

DEC. 30, 1979 CAVERN PRESSURE EQUAL TO - 246.2 psig

NET INJECTION OF 557,019. MCF

CAVERN PRESSURE INCREASED APPROXIMATELY 70 psig.

@ 8.9447 m²cf/psig.

NET INJECTION SHOULD BE EQUAL TO. 626,129. MCF

INSTEAD ONLY 557,019 MCF WAS INJECTED

THEREFORE A SURPLUS OF

- 69,110 MCF @ 14.65

JAN 1, 1980 TO JAN 31, 1980

JANUARY 1, 1980 CAVERN PRESSURE EQUAL TO - 249.7 PSIG

JANUARY 31, 1980 CAVERN PRESSURE EQUAL TO 166.5 PSIG.

NET WITHDRAWAL OF 536,067 MCF

CAVERN PRESSURE DROPPED APPROXIMATELY - 83.2 PSIG

@ 8.9447 M²CF/PSIG.

NET WITHDRAWAL SHOULD OF REQUIRED 744,199 MCF

INSTEAD ONLY 557,019 MCF WAS WITHDRAWN

THEREFORE A L&U OF

+ 187,180 MCF

PSC 039525

FEBRUARY 1, 1980 TO FEB 29, 1980.

FEB 1, 1980 CAVERN PRESSURE = 177.1

FEB 29, 1980 CAVERN PRESSURE = 246.3

NET INJECTION OF 560, 434.

CAVERN PRESSURE INCREASED APPROXIMATELY - 69.2 psig

@ 8.9447 mcf/psig - 618,973

Therefore we have a surplus of

- 58,539 MCF @ 14.65.

MARCH 1, 1980 TO MARCH 31, 1980

MARCH 1, 1980 — 244.8

MARCH 31, 1980 — 248.7

NET INJECTION — 56,203

SHOULD REQUIRE — 3.9 psig = 34,884

+ 22,018

TOTAL L+U = 179,121 MCF.

PSC 039527

ACTUAL:

80.1 psig on 5/11/79

241.5 psig on 7/14/80.

NET INJECTION - 1550302 MCF.

$P_1 = 241.5 = 253.47$ psia
$P_2 = 80.1 = 92.07$ psia
$Q_F = 1550.302\ m^2CF$ @ 14.65
$X = 790$ ft
$G = 0.653$
$T = 520\ °R$
$P_3 = 250$ psig $= 261.97$ psia
$P_4 = 60$ psig $= 71.97$ psia

$$P_A = P_B\, e^{\left(.01877 \frac{GX}{T}\right)} = P_B(1.0188)$$

$P_{A1} = 253.47\ (1.0188) = \cancel{258.24}$
$P_{A2} = 92.07\ (1.0188) = 93.80$
$P_{A3} = 261.97\ (1.0188) = 266.90$
$P_{A4} = 71.97\ (1.0188) = 73.32$

$P_{A1} = 258.24\ /\ .98087 = 263.28$
$P_{A2} = 93.80\ /\ .99108 = \cancel{94.64}$
$P_{A3} = 266.90\ /\ .98070 = 272.32$
$P_{A4} = 73.32\ /\ .99532 = 73.66$

$$m = \Delta Y / \Delta X = \frac{265.35 - 92.40}{1,550,302} = .1083 - 9.23$$

7/14/80.

111.8 ON. 8/20/79.
241.5 ON 7/14/80.

NET INJECTION. - 1550302.

PRESSURE BASE = 11.97 psia.

P_1 = 241.5 psig = 253.47 psia.
P_2 = 111.8 psig = 123.77 psia.
Q_T = 1,550.302 M^2CF @ 14.65
X = 790 ft.
G = 0.653
T = 520 °R
P_3 = 250 psig.

$$P_A = P_B\, e^{\left(.01877 \frac{GX}{T}\right)} = P_B(1.0188)$$

P_{A1} = 253.47 (1.0188) = 258.24 psig (BOTTOM HOLE CORRECTED)
P_{A2} = 123.77 (1.0188) = 126.10 psig. " "
P_{A3} = 261.97 (1.0188) = 266.90 psig. " "
P_{A4} = 71.97 (1.0188) = 73.32 psig. " "

(TABLE A-15) KATE

		AT psig
F_{PV_1} = 1.0195	Z_1 = .98087	
F_{PV_2} = 1.009	Z_2 = .99108	
F_{PV_3} = 1.0203	Z_3 = .98010	
F_{PV_4} = 1.0047	Z_4 = .99532	

P_{A1} = 258.24 / .98087 = 263.28 psia
P_{A2} = 126.10 / .99108 = 127.24 psia
P_{A3} = 266.90 / .98010 = 272.32 psig
P_{A4} = 73.32 / .99532 = 73.66 psia.

$m = \frac{\Delta Y}{\Delta X}$ WHERE ΔY = CHANGE IN PRESSURE DURING DRAWDOWN PERIOD

ΔX = CHANGE IN VOLUME IN M^3CF FOR DRAWDOWN PERIOD.

PRESSURE BASE SHOULD BE 14.65

$P_{A1} = 256.15 \ (1.0188) = 260.97$
$P_{A2} = 125.65 \ (1.0188) = 128.01$
$P_{A3} = 264.64 \ (1.0188) = 269.62$
$P_{A4} = 74.65 \ (1.0188) = 76.05$

CORRECTED FOR BOTTOM HOLE.

$P_{A1} = 260.97 / .98087 = 265.35$
$P_{A2} = 128.01 / .99108 = 129.16$
$P_{A3} = 269.62 / .9801 = 275.09$
$P_{A4} = 76.05 / .99532 = 76.41$

NOW $\Delta Y / \Delta X = \frac{265.35 - 129.16}{1,550,302} = .0878474$

OR $\frac{1}{m} = 11.3834$

SOLVING FOR X @ THE FOUR BOTTOM-HOLE PRESSURES.

$X_1 = 265.35 \ (11.3834) = 3020.585$
$X_2 = 129.16 \ (11.3834) = 1470.280$
$X_3 = 275.09 \ (11.3834) = 3131.460$
$X_4 = 76.41 \ (11.3834) = 869.805$

TOTAL WORKING VOLUME = $X_3 - X_4$.

3131.460 m^2CF − 869.805 m^2CF = 2261.655 m^2CF

STORED VOLUME TOTALS − X_3 = 3131.460 m^2CF

$$m = \frac{250}{3131.460 \; m^2CF \; @ \; 14.65} = .079835$$

$X = 12.5258 \, Y$

∴ AT Y = 250 PSIG VOLUME IN STORAGE = 3131.450 m^2CF

AT Y = 60 PSIG VOLUME IN STORAGE = 751.548 m^2CF

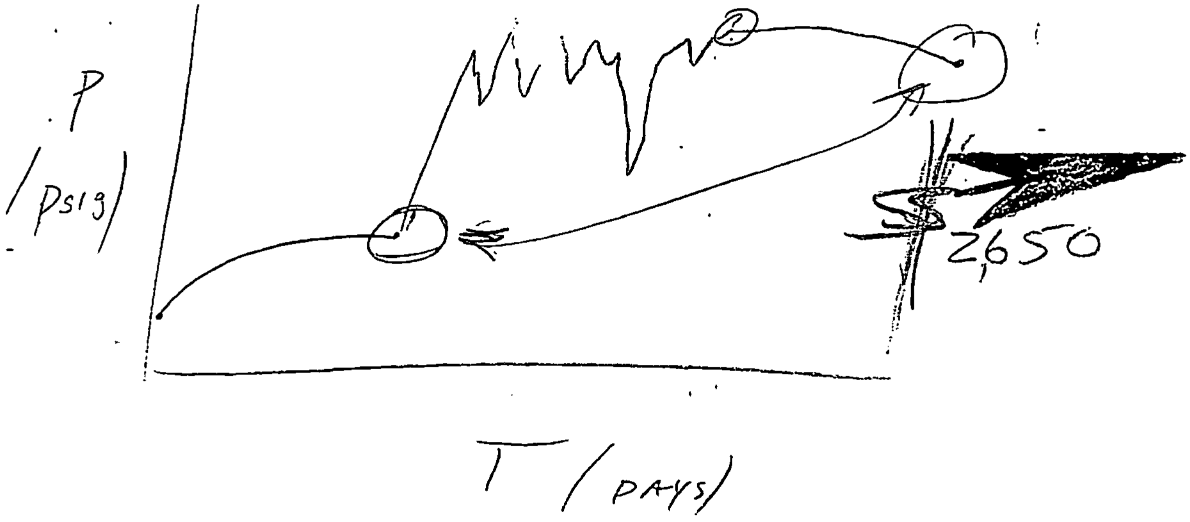
TOTAL VOLUME	= 3,131,450	MCF
WORKING VOLUME	= 2,379,920	MCF
CUSHION VOLUME	= 751,548	MCF.

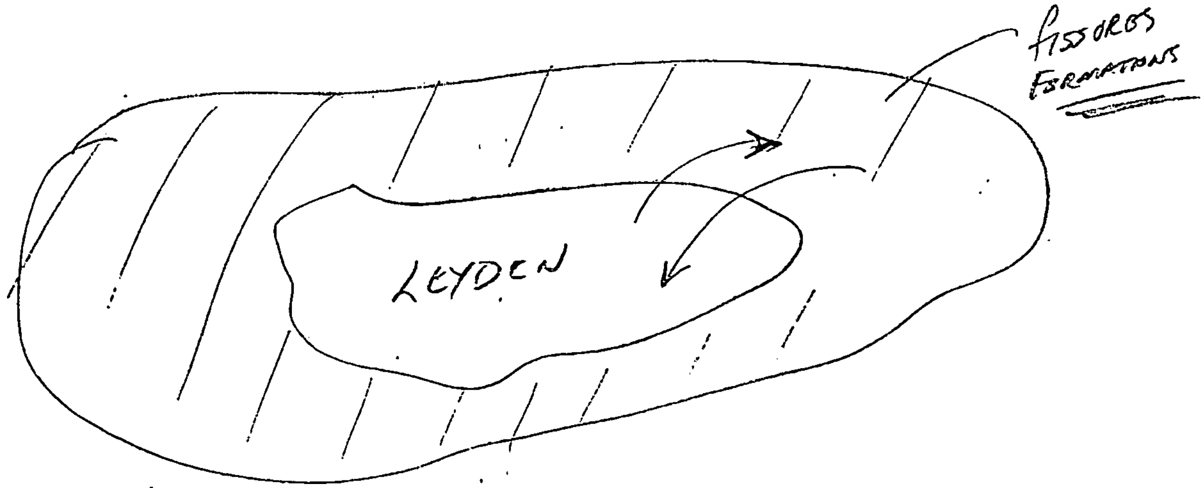
NOW CONTINUE WITH 11.97

$$m = \Delta Y / \Delta X = \frac{263.28 - 127.24}{1550.302} = .0877506$$

$$\frac{1}{m} = 11.3959$$ (LARGER VOLUMES BUT WRONG PRESSURE)

PSC 039531





BINGO!

THIS HELPS THE L+U CALCULATIONS
DRAMATICALLY

(FOLLOWS)

L + U CALCULATIONS.

NOV 1, 1979 PRESSURE IN CAVERN = 241.7 psig.

JULY 14, 1980 PRESSURE IN CAVERN = 241.5 psig.

INJECTIONS DURING THIS TIME PERIOD — 1885371 MCF
WITHDRAWALS DURING THIS TIME PERIOD — 1670439 MCF

NET INJECTION — 214,932 MCF.

BUT MOST OF THIS GAS HAS BEEN USED TO FILL THE VOIDS AND FISHERS ASSOCIATED AROUND THE CAVERN.

ON 9/14/72 STABILIZED CAVERN PRESSURE WAS 1326.5 psig

SUMMARY OF GAS DELIVERED REPORT SHOWS 1671014 MCF @ 14.65.

FROM 9/14/72 TO 8/13/80

NET INJECTION = 1,906,739 MCF @ 14.65

∴ 1671014 MCF + 1,906,739 MCF

= 3,577,753 MCF.

ACTUAL VOLUME ON 8/13/80 = 2,812,084 MCF

∴ TOTAL L+U REPORTED FROM 9/72 → 8/80

= 765,669

REPORTED.

9/14/72 — 132.5 psig — 1671014 MCF @ 14.65

NET INJECTION = 1906739 MCF @ 14.65.

8/13/80 — 240.9 psig — 2,812,084.

CAVERN PRESSURE WENT FROM 132.5 psig

TO 240.9 psig.

240.9 psig = 2,800,655 MCF

L+U = 777,098 SHOULD OF BEEN REPORTED.

765,669 REPORTED SO FAR.

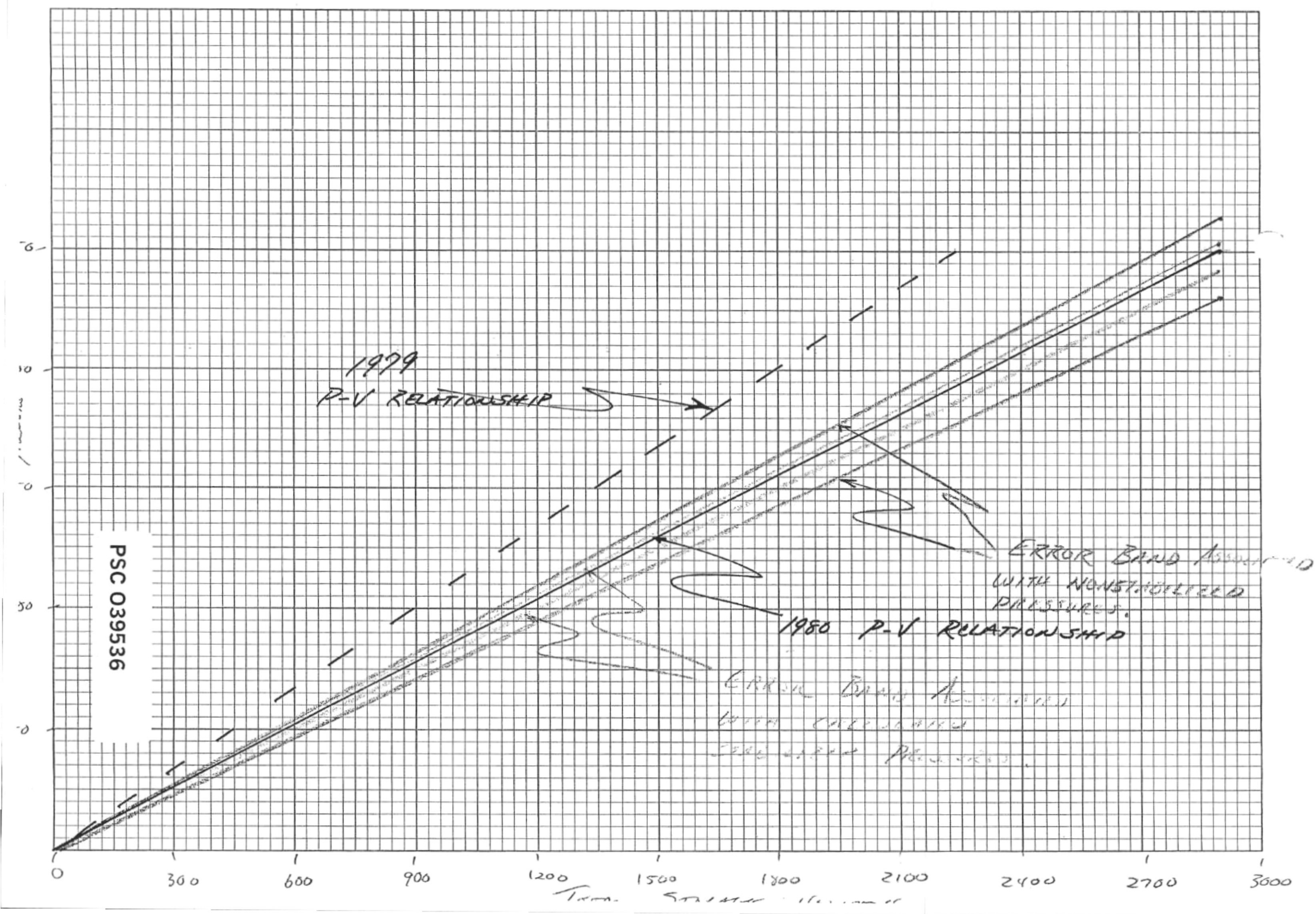
L+U THIS YEAR = 11,429

11,428

PSC 039535

K&E 10 X 10 TO THE INCH • 7 X 10 INCHES
KEUFFEL & ESSER CO. MADE IN U.S.A.

46 0780



Oct 31, 1979 - 241.2 psig. - 2752.682. M^2CF

August 18 1980 - 240.9 - 2,812.084 M^2CF

NET INJECTION = 59,402 MCF as L&U

50,000 = L&U

53,000 = L&U

L+U CALCULATION

8/20/79 STABILIZED CAVERN PRESSURE = 111.7 psig

DATE	INJECTIONS	WITHDRAWALS	NET
8/20 - 8/30	610,935	–	+ 610,935
9/79	698,012	–	+ 698,012
10/79	67,830	41,407	+ 26,423
	1,376,777	41,407	1,335,370

CAVERN PRESSURE ON 11/1/80 = 241.7

$$\frac{\left[(111.7 \text{ psig}) \times \left(11.6258\ m^2CF/\text{psig}\right)\right] + 1,335,370}{11.6258\ m^2CF/\text{psig}} = 226.56 \text{ psig}$$

ACTUAL CAVERN PRESSURE = 241.7 psig

− 226.56 psig

15.14 psig

L+U = − (15.14)(11.6258)

= − 175,984 MCF

PSC 039538

L + U CALCULATIONS.

11/1/79 CAVERN PRESSURE = 241.7 psig.

DATE	INJECTIONS	WITHDRAWALS	NET
11/79	271,306	692,621	−421,315
12/79	843,305	286,286	+557,019
1/80	75,473	611,540	−536,067
2/80	595,582	35,148	+560,434
3/80	99,705	42,802	+56,903
4/80	—	2,042	−2,042
5/80	—	—	—
6/80	—	—	—
7/80	—	—	—
8/80	4,379	—	+4379
9/80	105,798	—	+105,798
10/80	—	—	—
	1,995,548	1,670,439	325,109

STABILIZED CAVERN PRESSURE ON 10/31/80 = 247.3 psig.

THE CAVERN PRESSURE ON 11/1/79 CORRESPON TO A TOTAL WORKING VOLUME OF

$$(241.7\ \text{psig}) \times (11.6258\ m^2CF/\text{psig}) = 2809.956\ m^2CF$$

PSC 039539

ADDING THE NET ACTIVITY FROM 11/1/79 → 10/31/80
GIVES A NEW TOTAL STORAGE INVENTORY OF

2,809,956 MCF + 325,109 MCF = 3,135,065 MCF

THIS VOLUME CORRESPONDS TO A NEW CAVERN
PRESSURE ON 10/31/80 OF

$$\frac{3,135,267 \text{ MCF}}{11.6258 \text{ MCF/psig}} = 269.66 \text{ psig}$$

HOWEVER ACTUAL CAVERN PRESSURE ON 10/31/80 WAS
247.3 PSIG LEAVING A DIFFERENCE OF
(269.66 psig − 247.3 psig) = 22.36 psig

THEREFORE L+U FROM 11/1/79 → 10/31/80 =
22.36 psig (11.6258 MCF/psig) = 259,953 MCF

PSC 039540

L+U CALCULATIONS

8/20/79 ⇒ STABILIZED:
CAVERN PRESSURE = 111.7 psig

	INJECTIONS (+)	WITHDRAWALS (-)	NET
8/20 - 8/30 -	610,935	—	+ 610,935
9/1 - 9/30 -	698,012	—	+ 698,012
10/1 - 10/31 -	67,830	41,407	+ 26,423
11/1 - 11/30 -	271,306	692,621	- 421,315
12/1 - 12/31 -	843,305	286,286	+ 557,019
1/1 - 1/31 -	75,473	611,540	- 536,067
2/1 - 2/29 -	595,582	35,148	+ 560,434
3/1 - 3/31 -	99,705	42,802	+ 56,903
4/1 - 4/30	—	2,042	- 2,042
5/1 - 5/30	—	—	
6/1 - 6/30	—	—	
7/1 - 7/30	—	—	
8/1 - 8/20	—	—	
	3,262,148	1,711,846	1,550,302 ✓

STABILIZED:
CAVERN PRESSURE
ON 8/20/80 - 240.5 psig.

L+U = 52,898 (80)

PSC 039541

L+U CALCULATIONS

9/8/78 – STABILIZED CAVERN PRESSURE = 122 psig

	+	−	
9/78	1,171,073	—	+ 1,171,073
10/78	85,282	—	+ 85,282
11/78	477,218	409,599	+ 67,619
12/78	677,579	1,193,606	− 516,027
1/79	550,747	669,617	− 118,870
2/79	893,229	222,492	+ 670,737
3/79	5,512	—	+ 5,512
4/79	1,635	982,234	− 980,599
5/79	—	351,673	− 351,673
6/79	—	—	
7/79	—	—	
8/79 → 10/80	3,372,325	1,713,981	+ 1,658,344
	7,234,600	5,543,202	1,691,398

STABILIZED CAVERN PRESSURE ON
10/31/80 – 247.3 psig

L+U = 234,685 MCF

− 155,530 MCF IN 1979

79,155 MCF (80)

PSC 039542

8/30/77 — STABILIZED CAVERN PRESSURE
113.9 psig

	+	−	NET
9/77 —	1,301,155	—	+ 1,301,155
10/77 —	144,939	35,717	+ 109,222
11/77 —	289,170	231,143	+ 58,027
12/77 —	704,850	656,023	+ 48,827
1/78 —	102,322	439,715	− 337,393
2/78 —	584,764	202,246	+ 382,518
3/78 —	201,392	212,971	− 11,579
4/78 —	—	1,305,139	− 1,305,139
5/78	—	—	—
6/78	—	—	—
7/78	—	—	—
8/78	—	—	—
9/78 → 10/80	7,234,600	5,543,202	+ 1,691,398
	10,563,192	8,626,156	1,937,036

10/31/80 STABILIZED CAVERN PRESSURE — 247.3 psig

L+U = 386,154 MCF
− 130,404 (1978 L+U) LOW BY 20,000
− 155,530 (1979 L+U)

100,220 MCF (80)

PSC 039543

8/31/76 STABILIZED CAVERN PRESSURE = 110.2

	+	−	NET
9/76 −	1,210,715	—	+ 1,210,715
10/76 −	189,200	69,805	+ 119,395
11/76 −	173,770	483,792	− 310,022
12/76 −	460,361	82,146	+ 378,215
1/77 −	350,593	509,160	− 158,567
2/77 −	228,709	1,807	+ 226,902
/77 −	44,581	22,667	+ 21,914
/77 −	—	534,209	− 534,209
/77 −	—	875,241	− 875,241
/77 −	—	—	—
/77	—	—	—
/77	—	—	—

/77 → 10/80

10,563,192	8,626,156	+ 1,937,036
13,221,121	11,204,983	2,016,138

10/31/80
STABILIZED CAVERN PRESSURE = 247.3

L+U = 422241

− 132,568 (77) HIGH BY 20,000 + 70,000 = 90,000
− 130,404 (78) LOW BY 20,000
− 155,530 (79) GOOD

3,902 MCF (80)

8/1/75 STABILIZED CAVERN PRESSURE = 123.7 psig.

	+	−	NET
8/75	856,282	−	+ 856,282
9/75	370,003	36,788	+ 333,215
10/75	55,357	−	+ 55,357
11/75	435,063	676,545	− 241,482
12/75	429,762	113,646	+ 316,116
1/76	250,161	274,372	− 24,211
2/76	314,715	247,188	+ 67,527
3/76	93,399	71,622	+ 21,777
4/76	−	1,223,755	− 1,223,755
5/76	−	241,695	− 241,695
/76	−	−	−
/76	−	−	−
/76	13,958	−	+ 13,958
FROM 1/76 → 10/80	13,221,121	11,204,983	+ 2016,158
	16,039,821	14,090,594	1,949,227.

CAVERN PRESSURE = 247.3 psig.

L+U = 512,278 MCF
− 19,667 (76) LOW BY 90,000
− 132,568 (77)
− 130,404 (78)
− 155,530 (79)

74,109 MCF (80)

8/28/74 STABILIZED CAVERN PRESSURE = 120.0 psig.

	+	−	NET.
8/74 −	307,455	−	+ 307,455
9/74 −	907,013	−	+ 907,013
10/74 −	134,304	45,883	+ 88,421
11/74 −	72,741	187,265	− 114,524
2/74 −	265,113	132,819	+ 132,294
1/75 −	365,563	316,977	+ 48,586
/75 −	480,078	515,024	− 34,946
/75 −	55,372	177,882	− 122,510
/75 −	130,669	1,186,617	− 1,055,948
5/75 −	−	28,371	− 28,371
/75 −	−	−	−
/75	−	−	−
/75 → 10/80	16,039,821	14,090,594	+ 1,949,227
	18,758,129	16,681,432	2,076,697

STABILIZED CAVERN PRESSURE = 247.3 psig.

L+U =

576,733 MCF
− 98,577 (75)
− 19,667 (76) Low by 90,000
− 132,568 (77) High by 20,000
− 130,404 (78) Low by 30,000
− 155,530 (79)

59,986 MCF (80)

9/1/73 Stabilized Cavern Pressure = 174.7 psig

	+	−	Net
9/73 −	593,240	48,145	+ 545,095
10/73 −	173,588	—	+ 173,588
11/73 −	103,749	70,226	+ 33,523
12/73 −	186,165	169,826	+ 16,339
1/74 −	406,864	689,783	− 282,919
/74 −	380,219	67,214	+ 313,005
/74 −	52,456	19,184	+ 33,272
/74 −	—	545,854	− 545,854
/74	—	758,191	− 758,191
/74	—	—	—
7/74	—	—	—
7/74 → 10/80	18,758,129	16,681,432	2,076,697
	20,654,410	19,049,855	1,604,555

10/31/80 Cavern Pressure = 247.3 psig

LCU = 760,522 MCF
− 106,043 (74)
− 98,577 (75)
− 19,667 (76)
− 132,568 (77)
− 130,404 (78)
− 155,530 (79)

117,733 MCF (80)

145.0 ?

9/14/72 STABILIZED CAVERN PRESSURE = 132.5 psig.

	+	—	NET
9/72	909,354	9,122	+ 900,232
10/72	89,362	85,132	+ 4,230
/72	274,623	120,346	+ 154,277
2/72	559,990	611,888	- 51,898
/73	539,896	545,053	- 5,157
/73	315,012	217,839	+ 97,173
/73	86,215	103,770	- 17,555
/73	—	599,158	- 599,158
/73	—	58,562	- 58,562
/73	—	—	—
/73	—	188	- 188
/73	—	—	—

/73 → 10/80

20,654,410	19,049,855	1,604,555
23,428,862	21,400,913	2,027,949

STABILIZED CAVERN PRESSURE ON 10/80 - 247.3 psig

L+U = 693,307
- 122,880 (73) TOO HIGH
- 106,043 (74)
- 98,577 (75)
- 19,667 (76)
- 132,568 (77)
- 130,404 (78)
- 155,530 (79)

(80)

PSC 039548

ON 9/14/71 STABILIZED CAVERN PRESSURE = 147.5 psig.

ON 9/14/72 STABILIZED CAVERN PRESSURE = 132.5 psig

INJECTIONS FROM 9/14/71 → 9/14/72 = 1,239,434 MCF

WITHDRAWALS FROM 9/14/71 → 9/14/72 = 1,944,931 MCF

$L+U = (1{,}239{,}434 \text{ MCF} - 1{,}944{,}931 \text{ MCF}) - (132.5 - 147.5)(11625.8 \frac{\text{MCF}}{\text{psig}})$

71→72 $L+U = -$

PSC 039549

L+U CALCULATION

8/20/79

STABILIZED CAVERN PRESSURE = 111.7 psig.

DATE.	INJECTIONS	WITHDRAWALS	NET
8/20 - 8/30	610,935	—	+ 610,935
9/1 — 9/30	698,012	—	+ 698,012
10/1 — 10/31	67,830	41,407	+ 26,423
11/1 — 11/30	271,306	692,621	- 421,315
12/1 → 12/31	843,305	286,286	+ 557,019
1/1 → 1/31	75,473	611,540	- 536,067
2/1 → 2/29	595,582	35,148	+ 560,434
3/1 → 3/31	99,705	42,802	+ 56,903
4/1 → 4/30	—	2,042	- 2,042
5/1 → 5/30	—	—	—
6/1 → 6/30	—	—	—
7/1 → 7/30	—	—	—
8/1 → 8/30	4,379	—	+ 4379
9/1 → 9/14	—	—	—
	3,266,527	1,711,846	1,554,681

STABILIZED CAVERN
PRESSURE ON 9/14/80 = 239.7 psig

L+U CALCULATION

AT A STABILIZED CAVERN PRESSURE OF
111.7 psig ON 8/20/79, THIS CORRESPONDS TO
A TOTAL GAS IN STORAGE OF

$(111.7 \text{ psig}) \times (11.6258 \text{ m}^2\text{CF/psig}) = 1{,}298.602 \text{ m}^2\text{CF}$

ADDING THE NET ACTIVITY OF 1,554,681 FROM 8/20/79
TO 9/14/80 GIVES

1,298,602 MCF + 1,554,681 MCF = 2,853,283 MCF

THIS VOLUME EQUATES TO A FINAL STABILIZED
CAVERN PRESSURE OF

$$\frac{2{,}853.283 \text{ m}^2\text{CF}}{11.6258 \text{ m}^2\text{CF/psig}} = 245.43 \text{ psig}$$

HOWEVER ACTUAL FINAL PRESSURE WAS 239.7 psig
THEREFORE (245.43 psig − 239.7 psig = 5.73 psig)
5.73 psig WAS LOST. THIS PRESSURE CORRESPONDS
TO AN L+U OF

$5.73 \text{ psig} \times 11.6258 \text{ m}^2\text{CF/psig} = 66.616 \text{ m}^2\text{CF}$

$\therefore$ L+U FROM 8/20/79 → 9/14/80 = 66,616 MCF

INTER-DEPARTMENT MEMO—PUBLIC SERVICE COMPANY OF COLORADO

DATE February 2, 1972

TO Mr. L. W. Brown, Superintendent — Gas Engineering (DEPARTMENT OR DIVISION)

FROM Roy Elwell — Gas Engineering (DEPARTMENT OR DIVISION)

ATTN.

SUBJ. 1972 Leyden Drawdown

It was recently recommended and approved that 345 M^2CF of storage inventory at Leyden be written off to L & U at the end of 1971. This volume represents the accumulated L & U for the period of January 1, 1966 through October, 1971.

345 000 mcf / 5 3/4 years = 60 000 mcf/y or 0.06 BCF/y

Reference to the attached graph and the following data indicates that the method of operation at Leyden is a contributing factor to this L & U volume.

At the beginning of each summer from 1966 through 1970, the Leyden Mine cavern pressure was reduced to approximately 100 psig and the cavern shut in for several months. The pressure was then raised to approximately 250 psig just prior to the heating season. At the end of 1970, the L & U volume was calculated for the period of January, 1966 through December, 1970 to cover the period since the last L & U write-off in December, 1965. The results of the 1970 calculations indicate that 236.7 M^2CF was the appropriate volume of L & U for the period, for a yearly average of 47.34 M^2CF.

During the summer of 1971, the Leyden Mine cavern pressure was left at approximately 220 psig. In November, 1971, the L & U was calculated again for the period of January, 1966 through October, 1971; and it was found that 345.0 M^2CF was the appropriate L & U volume. This indicates that during 1971 the L & U volume increased to 108.3 M^2CF, which is more than double the yearly average. It would appear that the higher cavern pressure maintained during 1971 contributed significantly to the increased L & U.

In order to examine the economics of drawing down the cavern versus not drawing down in 1972, it was assumed that the cavern pressure at Leyden will be 250 psig at the end of the 1971-72 heating season. It will cost \$22,100.00 to draw the cavern down to 100 psig, based on withdrawing 1105 M^2CF at the current royalty rate of \$.02/MCF. However, the use of the 1105 M^2CF of gas from Leyden in lieu of purchasing it from our supplier would delay an expenditure of approximately \$255,000.00 for four months (based on the 1971 current cost of commodity gas @ \$.2301/MCF). A four month delay of this expenditure at an 8% interest rate would save the Company \$6,800.00, making the true cost of lowering the cavern pressure \$15,300.00.

If the cavern pressure is allowed to remain at approximately 250 psig, the L & U volume for 1972 would be at least 108.3 M^2CF, the same as experienced during 1971. If the cavern pressure were lowered to approximately 100 psig, the L & U volume is expected to be approximately 50 M^2CF, the 1966 through 1970 average. The respective L & U expenditures would be \$24,920.00 and \$11,505.00 (based on the current cost of commodity gas at \$.2301/MCF) or a difference of \$13,415.00, which is the true cost of leaving the cavern at 250 psig during the summer.

DEPARTMENT MEMO—PUBLIC SERVICE COMPANY OF COLORADO

DATE February 2, 1972

TO Mr. L. W. Brown, Superintendent — Gas Engineering (DEPARTMENT OR DIVISION)

FROM Roy Elwell — Gas Engineering (DEPARTMENT OR DIVISION)

ATTN.

SUBJ. 1972 Leyden Drawdown -- Page 2

Therefore, the difference in cost between drawing the cavern down ($15,300.00) and the cost of not drawing down in 1972 ($13,415.00) is $1,885.00.

Even though the above economics slightly favor a no-drawdown operation during 1972, it is improbable that the cavern pressure will be as high as 250 psig at the end of the 1971-72 heating season; thus, making it even less expensive to drawdown. However, $1,885.00 appears to be a small price to pay to reasonably control our L & U losses and minimize a potentially dangerous accumulation of gas in an area that is rapidly urbanizing.

Also less L&U if no drawdown

It is recommended that the cavern be drawn down at the end of the 1971-72 heating season to 100 psig in an effort to reduce our L & U gas volume by at least 50% annually.

Roy

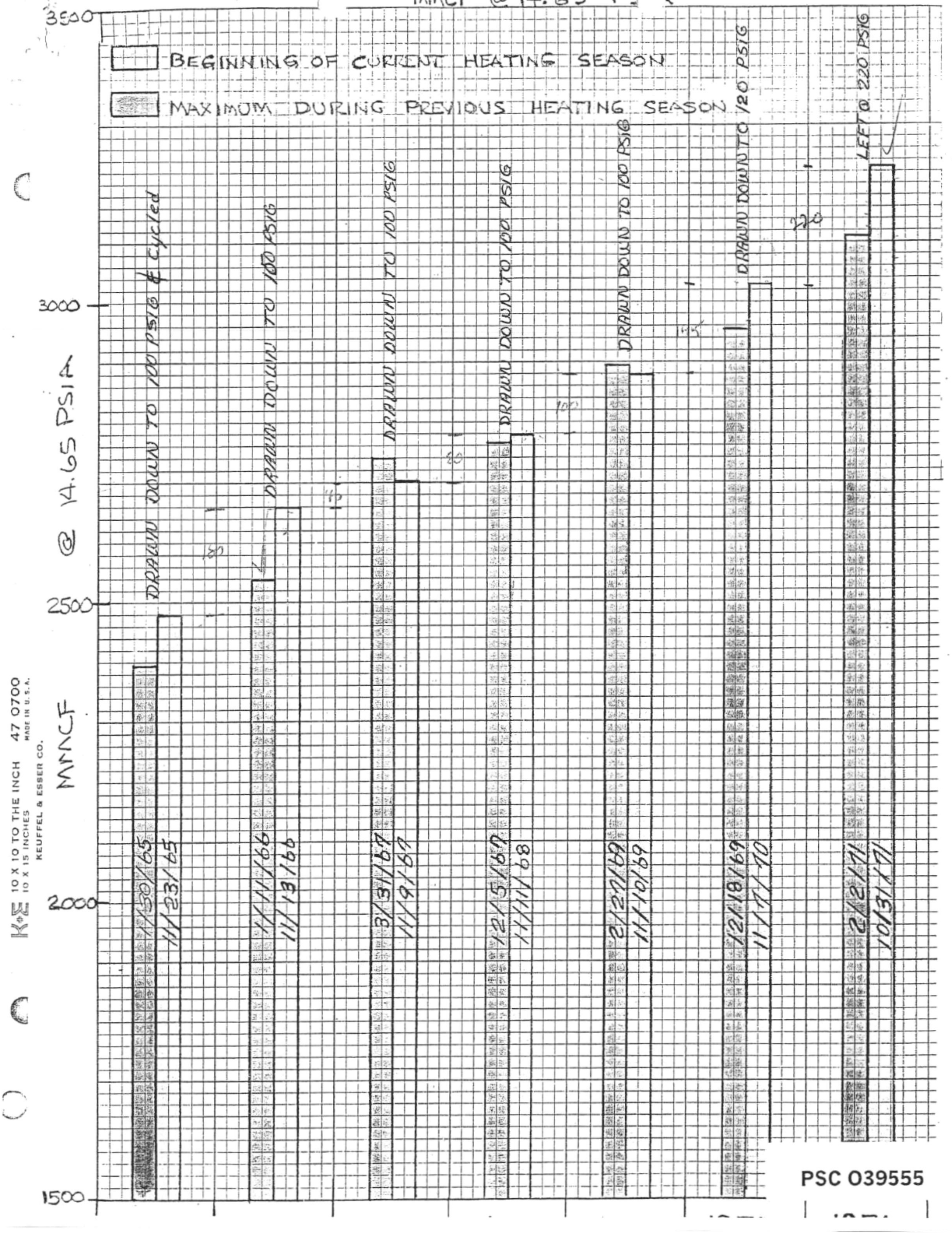
Roy Elwell

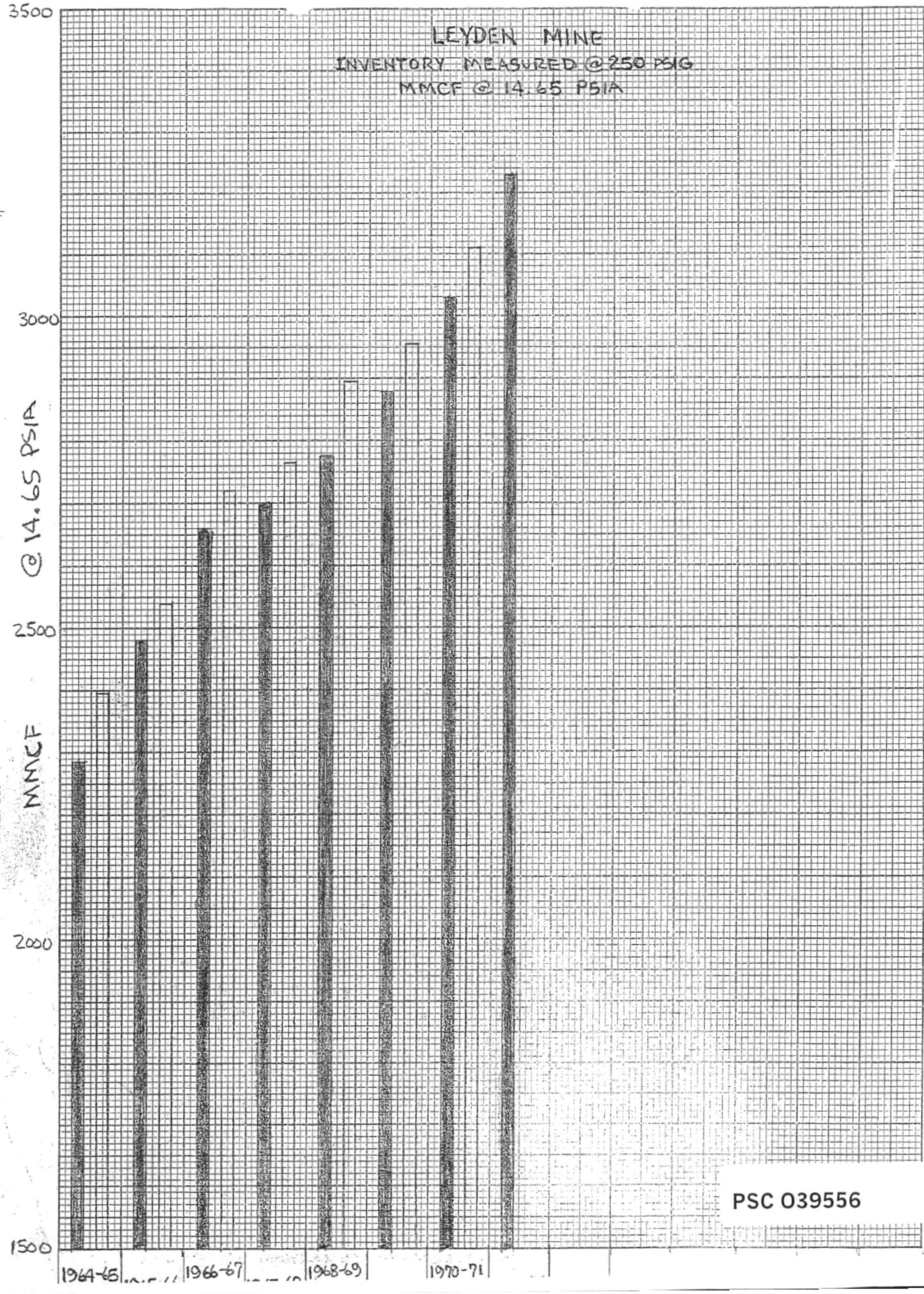
c

Work over #14
May want to plug & abandon #2

LEYDEN MINE

INVENTORY MEASURED @ 250 PSIG
MMCF @ 14.65 PS




LEYDEN MINE
INVENTORY MEASURED @ 250 PSIG
MMCF @ 14.65 PSIA
3500
3000
2500
2000
1500
@ 14.65 PSIA
MMCF
1964-65
1966-67
1968-69
1970-71
7 X 10 INCHES
KEUFFEL & ESSER CO.
MADE IN U.S.A.

FORM 850-22-0056

INTER-DEPARTMENT MEMO—PUBLIC SERVICE COMPANY OF COLORADO

DATE February 15, 1972

TO Mr. James P. Heckendorn, Superintendent — Gas Distribution (DEPARTMENT OR DIVISION)

FROM Mr. Robert M. Meddles, Superintendent — Leyden Gas Storage (DEPARTMENT OR DIVISION)

ATTN. Mr. Heckendorn

SUBJ. U & L Gas

The object of this report is to express my opinion concerning U & L Gas at the Leyden Gas Storage Project.

As Superintendent of this project, I feel a deep responsibility for any large expenditure of money associated with it. I feel that if I neglected to state my opinion concerning proposed work and investigation being done at Leyden, I would be remiss in my duty as Superintendent.

This report was written for the express purpose of making us all aware of facts that have, in the past few years, been forgotten. I hereby submit this report for one purpose only, "the good of the Company and the Leyden Gas Storage Project".

R. M. Meddles

R. M. MEDDLES
Superintendent
Leyden Gas Storage

Cy Furn:
Mr. John M. Hassoldt
Mr. Leroy W. Brown

1,805,664
50,000
.02.8
1805 50.00

PSC 039557

In 1971, the Company requested the aid of a Consultant in locating gas, lost or unaccounted for, at the Leyden Gas Storage Project. This gas will hereafter be referred to as "U & L Gas".

The Consultants preliminary report, dated July 26, 1971, addressed to Mr. John Hassoldt, indicates several pertinent facts that the Company has been aware of for some time. His recommendation in this report precipitated the logging of the entire project by Schlumberger Well Services in September of 1971. The results of this survey were reported in the Inter-Department Memo of October 6, 1971 to Mr. R. F. Jones from Mr. P. K. Triblehorn and Mr. N. H. Ottinger. This report was later discussed at a meeting attended by Messrs: R. F. Jones; J. C. Heckendorn; P. K. Triblehorn; E. J. Schuh; L. W. Brown; B. W. Beebe; N. H. Ottinger and myself.

After examining the Schlumberger logs at this meeting, the Consultant recommended that at the earliest time possible the #10 Observation Well and Water Wells #7 and #13 should be relogged and perforated as they show evidence of being in severe trouble from gas migrating behind the casings. It was pointed out that this anomaly existed in the initial McCullough log when the well was first drilled; however, the Consultant felt the McCullough logs were inferior and that their accuracy and sensitivity were questionable. On November 17, 1971, the #10 Observation Well was logged and perforated at five different zones at intervals selected by the Consultant. After perforating, there was no indication of gas behind the casing. The #13 Water Well was relogged but the engineer in charge decided against perforating it and also against the relogging of the #7 Water Well.

After having reviewed the four recommendations outlined in his initial report, I find that the Company has complied with three of the outlined recommendations. The fourth and final recommendation of deepening one of the observation wells is proposed in his Inter-Department Memo of January 18, 1972 to Mr. R. F. Jones.

At this time, I would like to state my opinion as to what I feel is required to eliminate the U & L Gas. The Companys' first concern should be the metering of gas in and out of the Cavern. It seems logical to assume that clean dry gas measured and injected into the Cavern will not be similar in metering when withdrawn if it is wet and contaminated with shale and coal debris, as evidenced in the Drip Leg at the Compressor Station. It would seem that the longer and harder (larger volumes required/hr) the withdrawal, the more the error would be magnified. A study of moving the metering installation from the Rockcatcher site to the Compressor Station site was done in the summer of 1971. The cost of this move was estimated at between 40 and $50,000.00. By moving this installation, the Company would benefit in two ways. First, more accurate metering and possibly a partial or complete solution to the U & L Gas because both injection and withdrawal metering will be done with clean gas. The second, and undoubtedly the largest, benefit would be protecting the meter run and Company responsibility from vandals, target shooters, possible damage from someone running off the road and into the meter run and the encroaching residential development that has moved into the area. This installation is located at the West side of the town of Leyden and produces noise. Since its installation, there have been, from time to time, complaints about these noises. If the meter installation were to be relocated, this problem would be solved.

Value?

PSC 039558

The Companys' next concern should be the #1 and #2 Shaft areas. As we know from past experience, there is leakage in this area. From laboratory tests of samples drawn from the vault area we have detected concentration of natural gas. This problem has not been encountered in Shafts #3 and #4 because the sealing methods employed by the Contractor were different. Shafts #1 and #2 do not have bottom hole concrete plugs. When the #7 Water Well is pumped, we encounter severe bubbling in the #1 and #2 Shaft area. The reason for this is that the water is removed to the 5,000' contour line of the east workings of the mine map, thus exposing the bottom of the #1 and #2 Shafts. This bubbling is quite severe when the Cavern pressure is between 220 and 250 psig. To pursue this further, I propose using a tracer in the Cavern. After some investigation, I would suggest the use of Sulphur Hexafluoride for reasons stated below:

1. It's cheap. The Electric Department uses it in trasnformers as a coolant.

2. It's non-toxic and will support life where it makes up 80% of the volume.

3. It can be detected as small as one (1) pp billion and electric companies have used it in stack gases to trace migration.

4. It's easy to handle and is detected through the use of a Chromatographer.

5. It's inert and has no corrosive properties.

6. It will not interfere with the use of other tracers or detection methods.

7. Above 260 psig., it will condense but when pressure falls below 260 psig., it will return to a gaseous state.

The small amount of Sulphur Hexafluoride required for detection also means that it would purge itself from the gas in a short period of time and also allow other tracers to be used if desired. This tracer could positively identify leaking storage gas and also gas migration can be traced. This information alone would be invaluable. How?

If, in a short time, tracer gas is found in the vaults or area around Shafts #1 and #2, this would necessitate remedial work in restoring a cap rock in the vicinity. This type of sealing can be done. If it becomes evident that sizable amounts of gas are venting from the shafts, then immediate action should be taken to establish a cap rock for the area. In conclusion, we should consider using Schlumberger only if the total logging cost for the same service is lower than the company we have been using. Since the beginning of our logging program, Wells #1, #2, #5, #9, #14, #15 and #16 have required, at various times, remedial work. This was detected through the logging survey used at that time. Since 1961, whenever wells were found to have bad cement or casing, remedial work was done as quickly as possible

I feel that the Company should make every effort to find the cause, or locate the source, of our U & L Gas; however, I feel we should begin this effort by first eliminating facts such as the metering and the confirmed leakage present in Shafts #1 and #2. Then, after the obvious problems have been eliminated and found not to be the total solution, we should investigate assumptions and probable causes.

We know that, in the past, we have had bad cement jobs and defective casings. Whenever these were discovered, they were repaired so as not to stimulate any horizontal gas migration. I feel that we may be pressuring up gas 25' to 50' above the back of the mine but not more than that, except in the areas of Shafts #1 and #2. Any other gas found behind the casing is migrating up and around a bad cement job. This belief is substantiated by Core Laboratory data on Wells #14 and #15, drilled in 1962 and #17b Observation Well and #18 Well, drilled in 1965. These wells exhibited no gas in the cuttings or drilling mud until lost circulation was encountered, which was within 50' of the Cavern.

My recommendation is as follows:

1. Move the metering from its present location to the Compressor Station. This could be completed first and if the problem of U & L Gas is solved, no need will exist for step #2.

2. Make quantative analysis of gas from the #2 Shaft at pressure ranges of 150 to 250 psig. Add a tracer to determine speed of movement and, if communication is direct, make preparations to establish a cap rock over the area.

annual cost of L & U ?

FORM 880-22-0038

INTER-DEPARTMENT MEMO—PUBLIC SERVICE COMPANY OF COLORADO

DATE December 12, 1972

TO Mr. R. F. Jonas, Superintendent of Gas Supply; Western Slope Gas Company
DEPARTMENT OR DIVISION

FROM B. W. Beebe, Consultant
DEPARTMENT OR DIVISION

ATTN. L. Brown

SUBJ. LEYDEN STORAGE PROJECT

Leyden gas storage is one of the most important and yet has the potential of being one of the most hazardous facilities of P.S.Co.'s gas system. The nature of the storage, a worked out mine, difficulties in successfully cementing casing in wells, plugging off shafts, location of and method of plugging core holes which may have been drilled from the surface during mining operations, highly irregular topography and the mine's location adjacent to the steeply dipping rocks of the foothills all add to potential hazard. Moreover, encroaching urban development when coupled with the geologic and mechanical hazards requires that all possible methods of monitoring the facility to detect leakage before it becomes dangerous should be carefully considered.

At present, wells are logged with gamma-ray neutron bi-annually to detect significant changes in log response which might be caused by movement of gas. In addition, surface gas detection devices are used periodically around wells, shafts, and the near vertical outcrop of the Laramie and Fox Hills sandstones west of the mine. These outcrops are of formations which form the roof (Laramie) and floor (Fox Hills) of the mine. It is inconceivable that these hard competent formations have not suffered fracturing when bent from virtually flat lying to near vertical. Moreover, records show several hundred water wells have been drilled in proximity to the mine. Many of these are completed in the Laramie or Fox Hills sandstones.

Should a leak develop behind the pipe in one of the wells, there may be no surface indication of gas. Gas may migrate up the bore hole to a porous zone, then along that porous zone to the surface on a hillside or in a ravine some distance from the well. This could occur between semi-annual logging periods.

The surface configuration in the vicinity is conducive to such leakage. The topography is characterized by rather steep hills cut by ravines. My concern over the gas bubbles in Barbara Gulch was caused by the topography which might cause leakage along steep hillslopes and in ravines. Hopefully, a change in log response would indicate a leak before it became serious. But a small leak might not be detectable and a dangerous amount of gas could build up before breaking out hundreds of feet from its source.

Crews should be alerted to report changes in appearance of vegetation or soil character along hillsides or in ravines as they work through the area. Monitoring should include selected areas particularly along hillsides and ravines and in water wells at some distance from the periphery of the mine.

The only feasible methods of detecting surface leakages over such a broad area, however are through infra-red or color aerial photography. Photographs should be taken yearly during the growing season when changes can be detected with more certainty.

To summarize, the present program should detect leaks around the shafts and wells. There are, however, other highly vulnerable areas which the current program will not detect within but in particular, outside of the storage areas. These include:

1. Improperly plugged coreholes, the location of which is unknown.

2. Water wells in the vicinity.

3. Hillsides where gas could migrate horizontally along bedding planes, accumulate and break out.

4. Ravines in and adjacent to the storage area where gas could accumulate in porous zones and break out.

5. Outcrops and buried outcrops of the near vertical standing Laramie and Fox Hills sandstones westward from the mine.

We believe that these various hazards and suggestions for detecting them be seriously considered. If personnel from either Fuelco's or Western's staff can be of assistance, do not hesitate to call on us.

B. W. Beebe
Consultant

BWB/gs

Jer

Comments on Leyden Report by Warren Beebe

1. It was not impossible to circulate cement to surface behind the casing. Ball Associates recommended that the casings be cemented with only 50 sacks. Wells #14, 15 and 16 were perforated and cemented to surface, with good return, several years after initial completion.

2. Apparently they do not realize that the pillars of coal were removed and the roof allowed to drop. If it did not drop sufficiently it was "shot down".

3. Gas bubbles discovered under the ice in Barbara Gulch were either in the spring or fall when the temperature was still conducive to vegetation decay. No ethane was detected in or near Barbara Gulch. Also, this occurred near Well #17, but I cannot remember if it was shortly before or after the "wash over" of the old casing.

G. Paul Cook

File Leyden 2 PU

QUESTIONS REGARDING MR. BEEBE'S JANUARY 18 LEYDEN STORAGE MEMO

1. Are we confident that no gas will migrate between the cement and casing or the cement and wall rock after the well is deepened to penetrate the cavern?

2. How do we remove the possibility of contaminating the formations through the existing perforations once the mine is penetrated?

3. If #10 is completed to the cavern, what makes it any different from any other injection/withdrawal well?

b

Lee Brown

PSC 039563

February 2, 1972

Mr. L. W. Brown, Superintendent — Gas Engineering

Roy Elwell — Gas Engineering

1972 Leyden Drawdown

It was recently recommended and approved that 345 M^2CF of storage inventory at Leyden be written off to L & U at the end of 1971. This volume represents the accumulated L & U for the period of January 1, 1966 through October, 1971.

Reference to the attached graph and the following data indicates that the method of operation at Leyden is a contributing factor to this L & U volume.

At the beginning of each summer from 1966 through 1970, the Leyden Mine cavern pressure was reduced to approximately 100 psig and the cavern shut in for several months. The pressure was then raised to approximately 250 psig just prior to the heating season. At the end of 1970, the L & U volume was calculated for the period of January, 1966 through December, 1970 to cover the period since the last L & U write-off in December, 1965. The results of the 1970 calculations indicate that 236.7 M^2CF was the appropriate volume of L & U for the period, for a yearly average of 47.34 M^2CF.

During the summer of 1971, the Leyden Mine cavern pressure was left at approximately 220 psig. In November, 1971, the L & U was calculated again for the period of January, 1966 through October, 1971; and it was found that 345.0 M^2CF was the appropriate L & U volume. This indicates that during 1971 the L & U volume increased to 108.3 M^2CF, which is more than double the yearly average. It would appear that the higher cavern pressure maintained during 1971 contributed significantly to the increased L & U.

In order to examine the economics of drawing down the cavern versus not drawing down in 1972, it was assumed that the cavern pressure at Leyden will be 250 psig at the end of the 1971-72 heating season. It will cost $22,100.00 to draw the cavern down to 100 psig, based on withdrawing 1105 M^2CF at the current royalty rate of $.02/MCF. However, the use of the 1105 M^2CF of gas from Leyden in lieu of purchasing it from our supplier would delay an expenditure of approximately $255,000.00 for four months (based on the 1971 current cost of commodity gas @ $.2301/MCF). A four month delay of this expenditure at an 8% interest rate would save the Company $6,800.00, making the true cost of lowering the cavern pressure $15,300.00.

If the cavern pressure is allowed to remain at approximately 250 psig, the L & U volume for 1972 would be at least 108.3 M^2CF, the same as experienced during 1971. If the cavern pressure were lowered to approximately 100 psig, the L & U volume is expected to be approximately 50 M^2CF, the 1966 through 1970 average. The respective L & U expenditures would be $24,920.00 and $11,505.00 (based on the current cost of commodity gas at $.2301/MCF) or a difference of $13,415.00, which is the true cost of leaving the cavern at 250 psig during the summer.

February 2, 1972

Mr. L. W. Brown, Superintendent — Gas Engineering

Roy Elwell — Gas Engineering

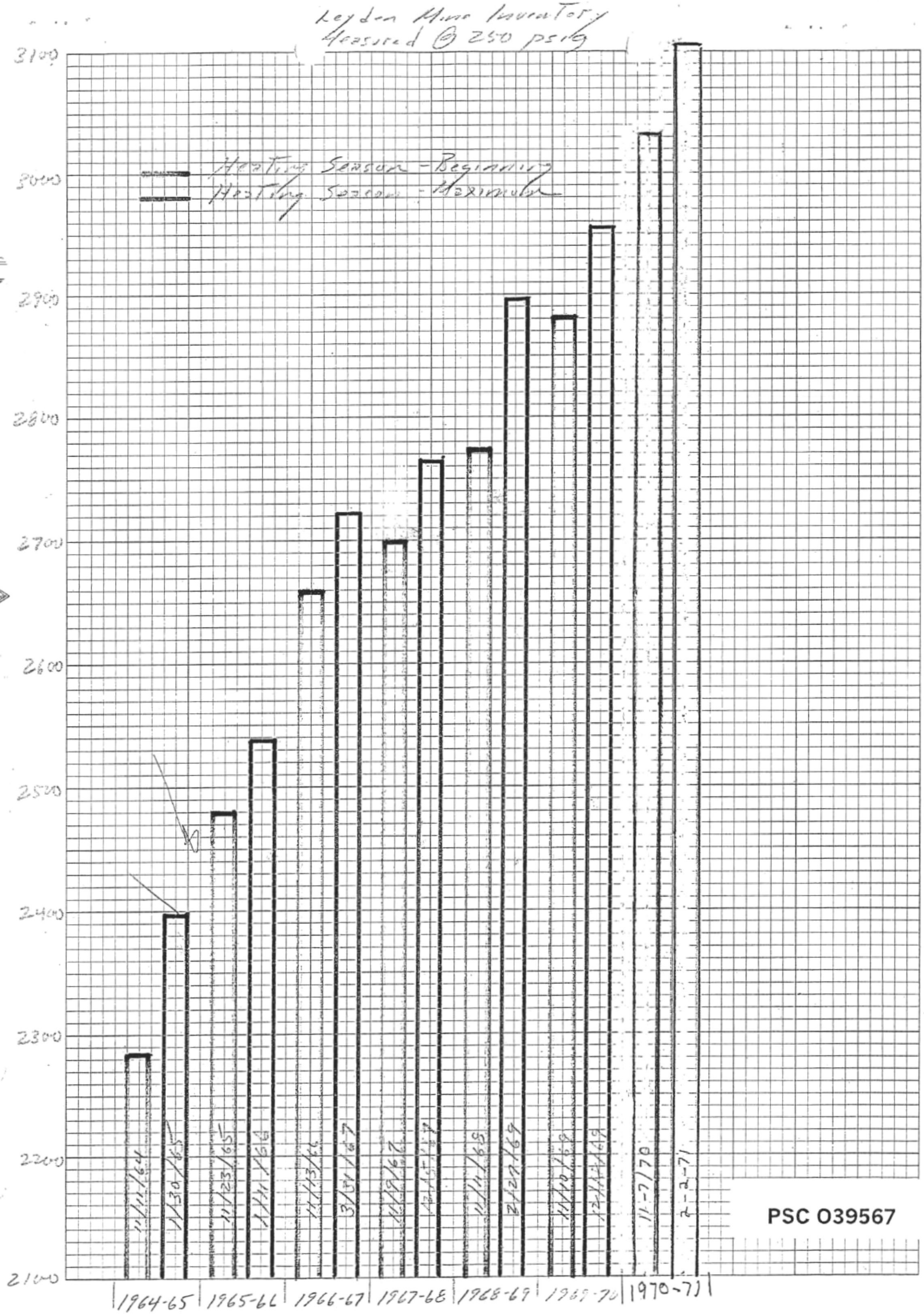
Therefore, the difference in cost between drawing the cavern down ($15,300.00) and the cost of not drawing down in 1972 ($13,415.00) is $1,885.00.

Even though the above economics slightly favor a no-drawdown operation during 1972, it is improbable that the cavern pressure will be as high as 250 psig at the end of the 1971-72 heating season; thus, making it even less expensive to drawdown. However, $1,885.00 appears to be a small price to pay to reasonably control our L & U losses and minimize a potentially dangerous accumulation of gas in an area that is rapidly urbanizing.

It is recommended that the cavern be drawn down at the end of the 1971-72 heating season to 100 psig in an effort to reduce our L & U gas volume by at least 50% annually.

Roy Elwell

c


Leyden Mine Inventory
Measured @ 250 psig
Heating Season - Beginning
Heating Season - Maximum
3100
3000
2900
2800
2700
2600
2500
2400
2300
2200
2100
11/11/64
1/30/65
11/23/65
1/11/66
11/13/66
3/31/67
11/19/67
2/27/69
11-7-70
2-2-71
1964-65
1965-66
1966-67
1967-68
1968-69
1969-70
1970-71

FORM 830-22-0058

File

INTER-DEPARTMENT MEMO—PUBLIC SERVICE COMPANY OF COLORADO

DATE November 18, 1971

TO Mr. L. W. Brown, Superintendent — Gas Engineering (DEPARTMENT OR DIVISION)

FROM Roy E. Elwell — Gas Engineering (DEPARTMENT OR DIVISION)

ATTN.

SUBJ. L & U - Leyden Storage Project

During production years the Colorado Mine Inspector reports that a total of 5,941,720 tons of coal was extracted from the Leyden Mine. The coal extracted from Leyden had a density of 84.9 pounds per cubic foot, or a maximum void of 140 MMCF for natural gas storage (5,941,720 x 2000#/ton ÷ 84.9#/cubic foot).

Assuming the full mined volume is available for the storage of natural gas and that none of this gas has been entrained in the adjacent non-mined formations, 2,681.2 MMCF can be stored at 250 psig or 280.57 $\frac{psia}{z}$.

Volume Calculations (MCF at 14.65 psia)

140.0 (280.57/14.65) = 2,681.2 MMCF

Chart Processing Department and Leyden Storage records indicate Leyden inventory was 3,026.2 MMCF at a dead weight reading of 250 psig on September 30, 1971.

Volume Inventory (M^2CF at 14.65 psia)

Inventory Volume	3,026.2 MMCF
Estimated Volume	2,681.2 MMCF
Capacity	345.0 MMCF

In December, 1965, 150,000 MCF at 14.65 psia of Leyden storage gas was written off as L & U. This gas was purchased from Western Slope Gas Company and/or Colorado-Wyoming Gas Company at the commodity rate of $0.205/MCF or $30,750.

In December, 1970, a memo from William Brackett recommended that an additional 200,000 MCF at 14.65 psia should be written off at the end of 1970 to balance our Leyden storage volume. Mr. Speer requested no write-off be made until 1971. Therefore, no storage gas was written off in 1970.

Our current calculations indicate that 345,000 MCF at 14.65 psia should be written off at the end of 1971 to balance the Leyden storage volume.

Commodity gas purchased from Western Slope Gas Company for Leyden cost $0.205/MCF from the date of the previous write-off in December, 1965 through April 17, 1970. The average cost of commodity gas purchased from Western Slope Gas Company during 1970, considering rate adjustments, was $0.2129/MCF. The weighted average cost of commodity gas for 1971, through October, is $0.2210/MCF.

FORM 830-22-0058

INTER-DEPARTMENT MEMO—PUBLIC SERVICE COMPANY OF COLORADO

DATE November 18, 1971

TO Mr. L. W. Brown, Superintendent — Gas Engineering (DEPARTMENT OR DIVISION)

FROM Roy E. Elwell — Gas Engineering (DEPARTMENT OR DIVISION)

ATTN.

SUBJ. L & U - Leyden Storage Project -- Page 2

If it is assumed the 200,000 MCF should have been written off equally in the years 1966 through 1970 at the respective cost of commodity gas and the remaining 145,000 MCF will be written off in 1971 at the current cost of commodity gas, then the breakdown would be as follows:

Year	MCF	Cost/MCF	Cost
1966	40,000	$.2050	$ 8,200
1967	40,000	.2050	8,200
1968	40,000	.2050	8,200
1969	40,000	.2050	8,200
1970	40,000	.2129	8,516
1971	145,000	.2210	32,045
Total	345,000		$73,361

Roy

Roy Elwell

c

PSC 039569

November 18, 1971

Mr. H. J. Johnson, Director — General Accounting

L. W. Brown, Superintendent — Gas Engineering

Account No. 11-1823-18 Gas Losses

We recommend 408,589 MCF at 12.37 psia (345,000 MCF @ 14.65 psia) be written off as lost and unaccounted for gas in underground storage operations through 1971. This volume represents the L & U gas since the last write-off in December, 1965.

L. W. Brown

c

PSC 039570

FORM 850-22-0058

INTER-DEPARTMENT MEMO—PUBLIC SERVICE COMPANY OF COLORADO

DATE January 8, 1970

TO Mr. Louis R. Arnold, Supvr. - Market & Supply — Gas Engineering (DEPARTMENT OR DIVISION)

FROM William E. Brackett — Gas Engineering (DEPARTMENT OR DIVISION)

ATTN.

SUBJ. Leyden Mine Storage Volume

As of December 31, 1969, the Leyden cavern pressure (closed) was 206 psig or 232.38 psia bottom hole pressure. During production years the Colorado Mine Inspector reports that a total of 5,941,720 tons of coal was extracted from the Leyden mine. The coal extracted from Leyden had a density of 84.9 pounds per cubic foot, or a maximum void of 140 MMCF for natural gas storage (5,941,720 tons x 2000#/ton/84.9/cubic foot). However, the results of the 1969 testing indicated that the available void is less due to the water encroachment and is estimated to be a maximum 124.3 MMCF. The following tabulation summarizes the inventory and related calculations on December 31, 1969.

Added Void Due to Water Pumping Assuming 7.48 Gallons/Cubic Foot

Gallons Pumped
63,549,600

Approx
Changed To 25,059,000 Gallons
See Sam Miller's File

Added Void Calculation

$$\frac{63{,}549{,}600 \text{ gallons}}{7.48 \text{ gallons/cubic foot}} = 8.5\ M^2CF$$

Available Void Storage Space

Estimated Void	124.25
Added Void	8.50
	132.75

Volume Calculations (MCF at 14.65 psia)

$132.75\ (232.38/14.65) = 2105\ M^2CF$

Volume Inventory (M^2CF at 14.65 psia)

Year End	2,534
Estimated Volume	2,105
Difference	429

In conclusion, the lost and unaccounted for gas at the Leyden Storage Project has decreased in the year 1969 over that in 1968. The inventory difference in 1968 was estimated at 445 M^2CF while the inventory difference in 1969 was 429 M^2CF. Therefore, the gas lost during 1969 is estimated at 16 M^2CF less than that volume lost in 1968.

William E. Brackett

William E. Brackett

WEB/cjp

PSC 039571

File

April 29, 1971

Mr. R. R. Midwinter, Director — Auditing

L. R. Arnold, Supervisor - Market & Supply — Gas Engineering

Gas Stored Underground - Inventory

The method of calculating gas inventory at the Leyden Mine has been changed somewhat from the method used in prior years. The current method assumes a volumetric approach and does not consider gas displaced through the summer water pumping program. The new method indicated that gas inventory in the cavern is increasing. At year ending 1971, inventory write-offs will occur to reflect the existing recoverable gas stored in the mine.

Mr. R. F. Jonas of Western Slope Gas Company should be contacted regarding similar data for Asbury Storage.

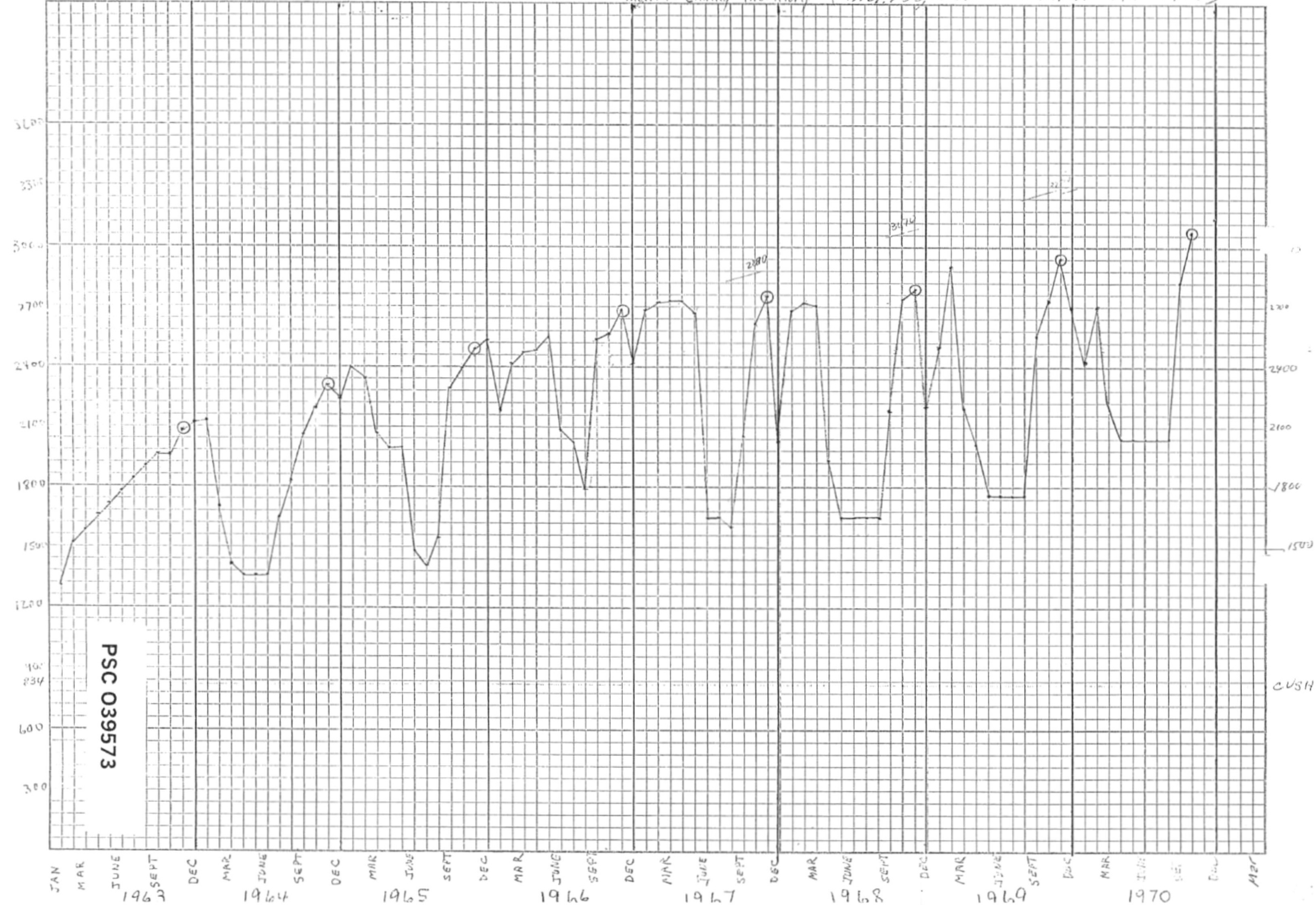
L. R. Arnold

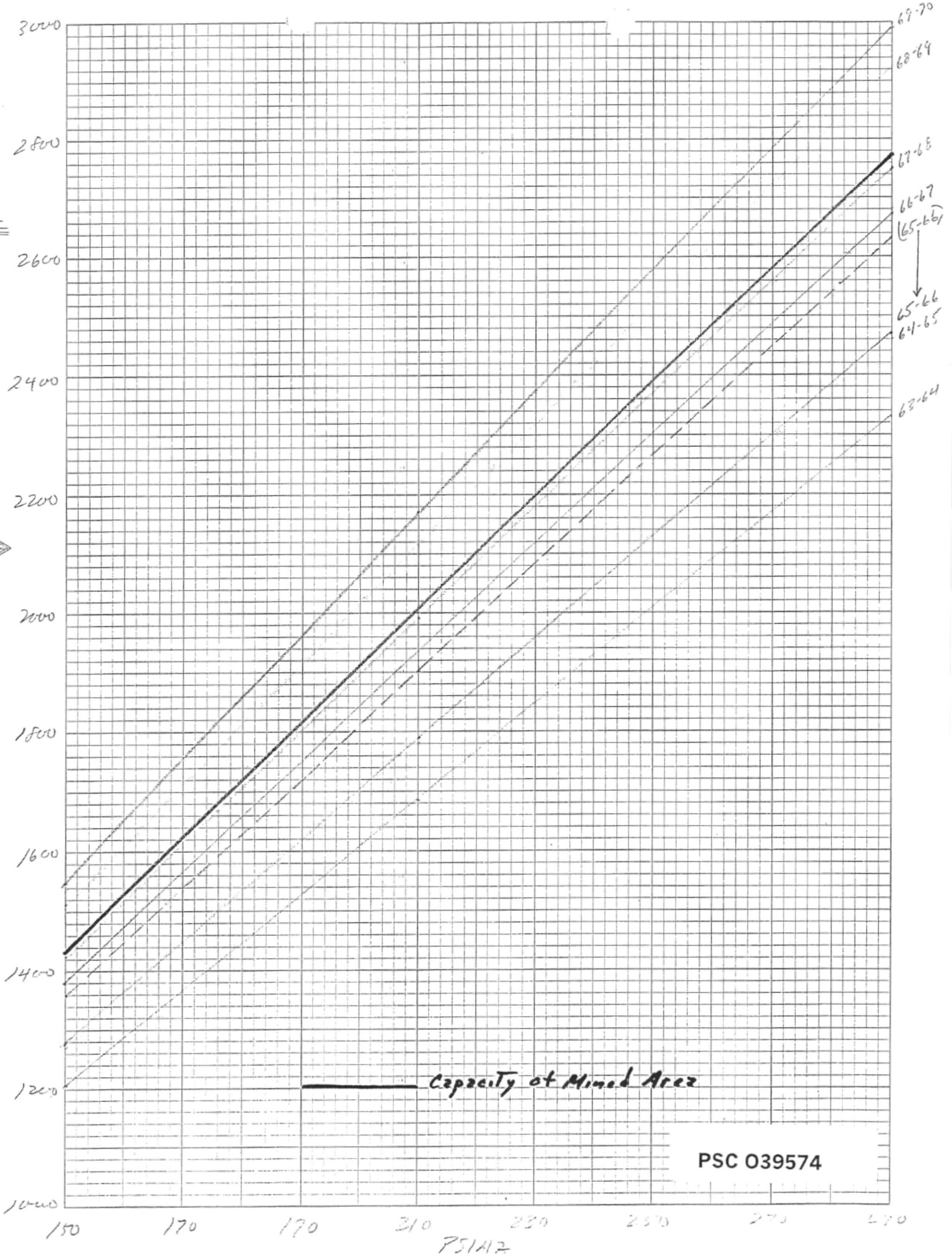
c

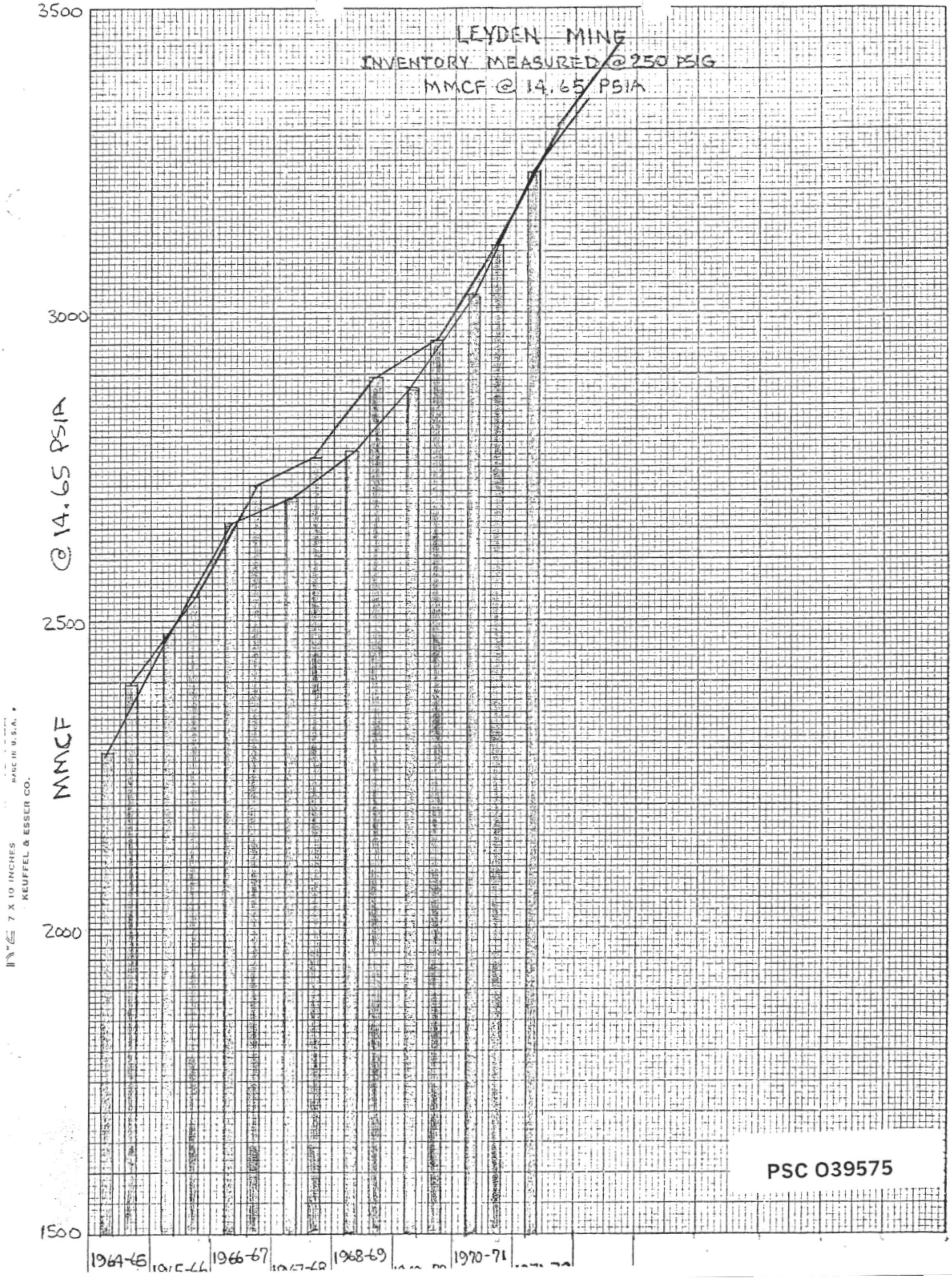
Summary of Gas Delivered - Leyden Storage Project

Month Ending Inventory (incl. 150,000 MCF written off 12/65)

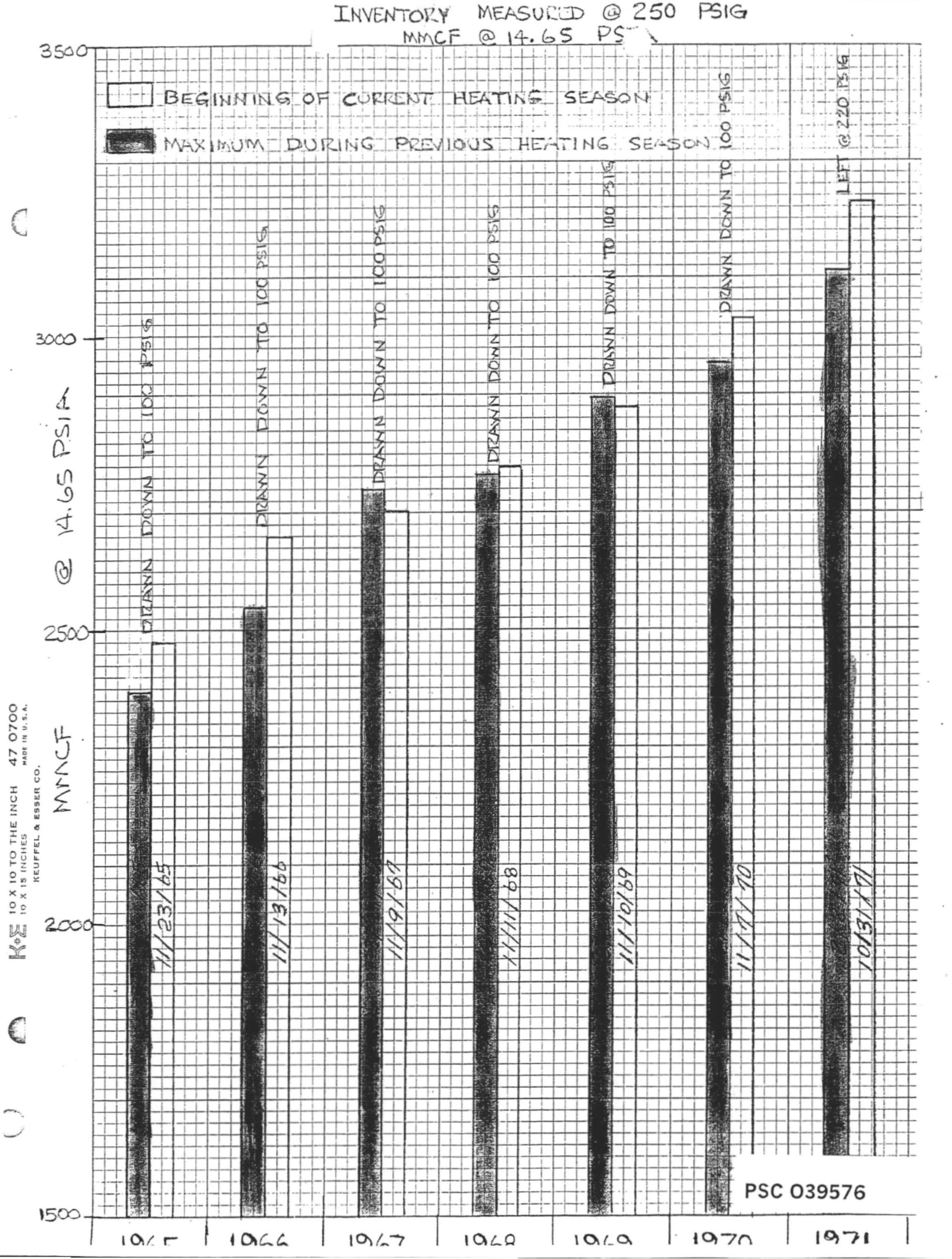
MMCF




3000
2800
2600
2400
2200
2000
1800
1600
1400
1200
1000
150
170
210
PSIA
69-70
68-69
67-68
66-67
(65-66)
65-66
64-65
63-64
Capacity of Mined Area



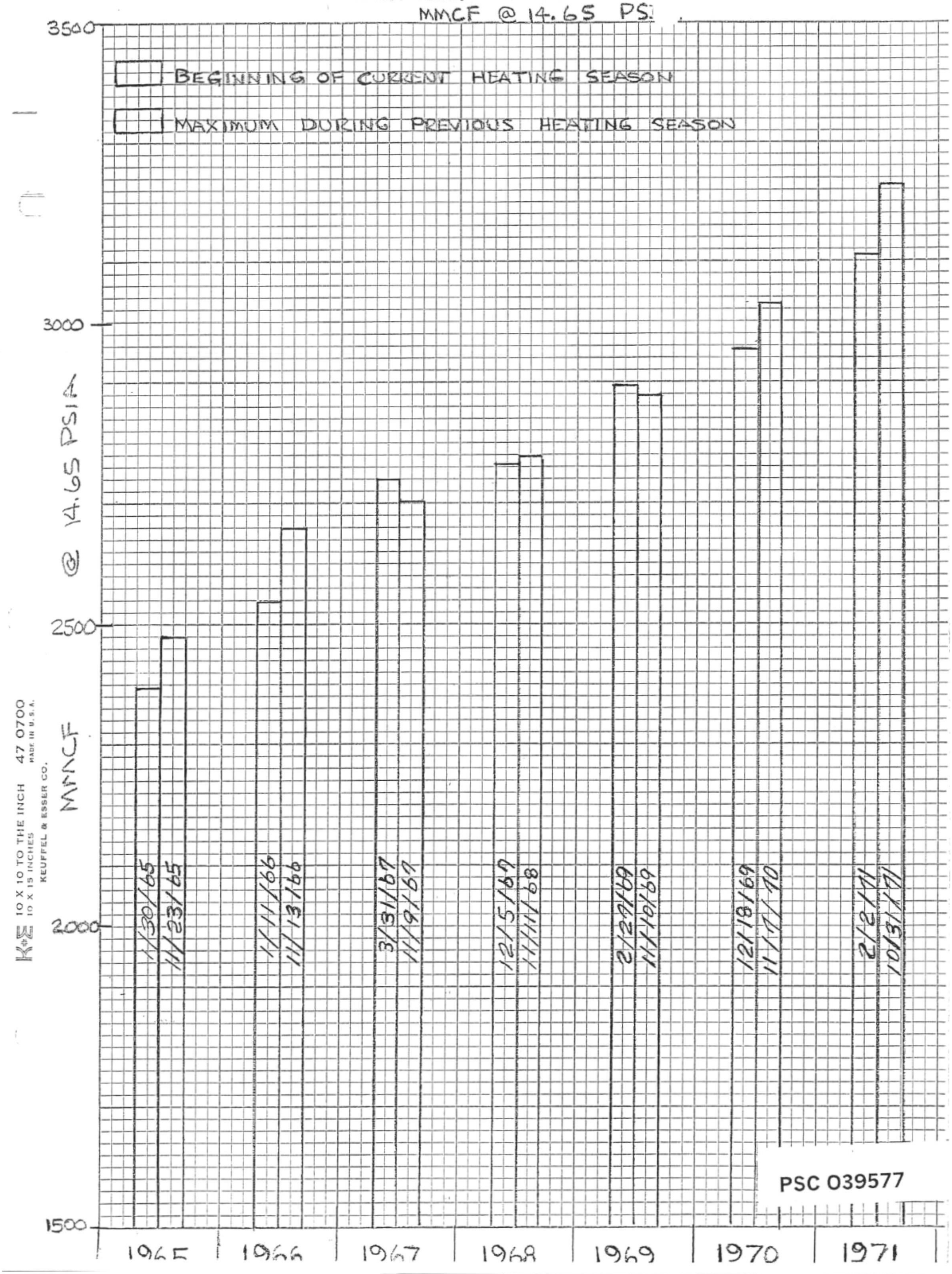
LEYDEN MINE
INVENTORY MEASURED @ 250 PSIG
MMCF @ 14.65 PSIA
MMCF @ 14.65 PSIA
3500
3000
2500
2000
1500
1964-65
1966-67
1968-69
1970-71
7 X 10 INCHES
KEUFFEL & ESSER CO.
MADE IN U.S.A.



INVENTORY MEASURED @ 250 PSIG
MMCF @ 14.65 PS
BEGINNING OF CURRENT HEATING SEASON
MAXIMUM DURING PREVIOUS HEATING SEASON
MMCF @ 14.65 PSIA
3500
3000
2500
2000
1500
DRAWN DOWN TO 100 PSIG
11/23/65
DRAWN DOWN TO 100 PSIG
11/13/66
DRAWN DOWN TO 100 PSIG
11/9/67
DRAWN DOWN TO 100 PSIG
11/11/68
DRAWN DOWN TO 100 PSIG
11/10/69
DRAWN DOWN TO 100 PSIG
11/11/70
LEFT @ 220 PSIG
10/31/71
1965
1966
1967
1968
1969
1970
1971
K+E 10 X 10 TO THE INCH 47 0700
10 X 15 INCHES MADE IN U.S.A.
KEUFFEL & ESSER CO.

PSC 039576

INVENTORY MEASURED @ 250 PSIG
MMCF @ 14.65 PSI



FORM 850-22-0058

File

INTER-DEPARTMENT MEMO—PUBLIC SERVICE COMPANY OF COLORADO

DATE: September 10, 1971

TO: Mr. Frank B. Fry, Vice President — Western Slope Gas Company
Mr. R. H. Freeman, Manager — Gas Operations
DEPARTMENT OR DIVISION

FROM: L. W. Brown, Superintendent — Gas Engineering
DEPARTMENT OR DIVISION

ATTN.

SUBJ. Refill of Leyden Mine

In preparation for the 1971-72 heating season, it will be necessary to schedule the Leyden refill operation to begin September 15, 1971.

It is estimated that approximately 250,000 Mcf will need to be injected in order to raise the storage pressure to 250 psig. The daily injection volume should be approximately 50,000 Mcf.

Mr. Forest Erickson will coordinate the details of the refill operation with Mr. Robert Meddles so that the shaft seals can be adequately maintained.

LWBrown
L. W. Brown

b

CC: Forest Erickson
Robert Jonas

December 9, 1970

Mr. Louis R. Arnold, Supvr., Market & Supply — Gas Engineering

William E. Brackett — Gas Engineering

Leyden L & U

During production years the Colorado Mine Inspector reports that a total of 5,941,720 tons of coal was extracted from the Leyden Mine. The coal extracted from Leyden had a density of 84.9 pounds per cubic foot, or a maximum void of 140 MMCF for natural gas storage (5,941,720 x 2000 #/ton/84.9#/cubic foot).

Assuming the full mined volume is available for the storage of natural gas and that none of this gas has been entrained in the adjacent non-mined formations, 2,681.2 MMCF can be stored at 250 psig or 280.57 psia.

Volume Calculations (MCF at 14.65 psia)

140.0 (280.57/14.65) = 2,681.2 MMCF

Chart Processing Department and Leyden Storage records indicate Leyden inventory was 2,917.9 MMCF at a deal weight reading of 250 psig on November 25, 1970.

Volume Inventory	(M^2CF at 14.65 psia)
Inventory Volume	2,917.9 MMCF
Estimated Volume	2,681.2 MMCF
Difference	236.7 MMCF

In conclusion, using the above premise, it is recommended 200 MMCF be written off as L & U at year end of 1970.

b

William E. Brackett

VERIFYING STORAGE INVENTORIES

AMERICAN GAS ASSOCIATION
Underground Storage Conference
Tulsa, Oklahoma

August 21, 1968

L. W. Brown
PUBLIC SERVICE COMPANY OF COLORADO

VERIFYING STORAGE INVENTORIES

Introduction

Public Service Company of Colorado stores natural gas in a void created by coal mining operations at the Leyden Lignite Mine, fourteen miles northwest of Denver, Colorado. The storage area is approximately 800 feet below the surface and consists of two overlapping working levels 8 to 10 feet in thickness as shown in figures 1 and 2. The coal was mined using the "Room and Pillar" method (Kelly, 1963, 8 p.). Most of the pillars in the upper workings were pulled, allowing the roof to cave in and fill the mine area with rubble. The lower workings are, for the most part, still supported by the pillars.

The records of the Colorado State Coal Mine Inspector indicate that a total of 5,941,720 tons of coal were produced from the Leyden Lignite Mine during its operating life. This would represent a total void of 140,000 mcf, or a potential storage inventory of 2,734,538 mcf at a maximum storage pressure of 250 psig. 2,681,215 @ 14.65 psia

Storage Inventory

It was expected that inventory control and verification would be a minor problem because gas would be confined in a definite void at pressures well below the hydrostatic head to prevent gas migration into the walls of the cavern. However, it was found that as the project developed the actual pressure-volume relationships deviated substantially from those predicted. Since our gas dispatchers depend heavily on adequate peak-shaving capacity from Leyden to serve the Denver area, a study was initiated in 1965 to find the true pressure-volume relationship. The annual requests by the auditors to substantiate inventory figures also made it imperative that we initiate this study.

Orifice Measurement Method

Integrated meter charts were used as the basic tool for estimating the total storage and working gas volumes until 1965. The Leyden Storage Project has a central metering point which is used to meter gas on both injection and withdrawal. There are no wellhead meters, and the gas is not cleaned or dehydrated on withdrawal prior to metering. However, an extensive test has shown that the net metering error at Leyden is only 1% high on withdrawal.

Volumetric Method

The volumetric method (Katz, 1959, p. 456-461) has been used as a check calculation for our metered volumes for several years. The volumetric calculations for total storage inventory have continued to deviate substantially from the metered volumes during this time. The auditors would prefer to write-off some of the excess volume; however, engineering has not agreed to this because continued experience with the production-pressure-decline method has indicated to us that some or all of the "unaccounted for" gas may be recovered. It should be noted that water pumping operations contribute additional void each year, but the increase in void is consistently below the increase in inventory.

Production-Pressure-Decline Method

The production-pressure-decline method (Katz, 1959, p. 461-462) was initiated at the beginning of the study as an additional tool to the orifice measurement and volumetric measurement methods. Pressure-decline curves were made and analyzed in detail over the full operating range of cavern pressure. Various withdrawal-injection rates and pressure stabilization periods were also used. During both injection and withdrawal, a gradual increase in volume per unit of pressure change is experienced as shown in figure 3.

The above observations indicated to us that gas was migrating from the cavern to the country rock outside the cavern void. This condition was tolerated for several heating seasons in hope that pressure stabilization would occur. However, sizeable increases in inventory occurred during each operating season which could not be accounted for by the volumetric measurement method. The gas migration had to be controlled to preclude it from finding its way to the surface or migrating so far from the void as to be permanently lost. Each summer we presisted in our efforts to control the inventory and analyze the pressure-volume relationship by means of the production-pressure-decline method. Here we noted that in those years in which low cavern pressure were reached, the inventory increase the following season was smaller than in those years in which high cavern pressures were maintained. In the summer of 1967, the cavern was deliberately drawn down to a minimum pressure of 100 psig and shut in for the remainder of the summer. As a result, the 1967-68 heating season marked the first time that the inventory at the beginning of the season was less than the inventory at the end of the previous heating season. In addition, the inventory buildup at the end of the 1967-68 season did not exceed our former peak inventory of 2725 M^2CF as shown in figure 4.

The pressure-volume relationship derived from the production-pressure-decline method is now used by Public Service Company of Colorado to determine the total void available for storage, the total volume in storage, and the total volume of working gas. The total void and corresponding storage volume are calculated after pressure stabilization, but the working gas volume is calculated prior to pressure stabilization. This is done because experience has shown that during operation we do not stay at any one pressure level long enough to benefit from the gas which may be recovered from the wall rock through pressure stabilization.

Conclusions

The production-pressure-decline method has been a very good tool for verifying storage inventories at the Leyden Storage project. A correlation with the orifice meter records and volumetric method has given us a method of controlling and even recovering a portion of the total storage inventory which has migrated from the cavern. In addition, the pressure-volume relationships developed by the production-pressure-decline method enable us to predict actual working gas volumes with a high degree of accuracy.

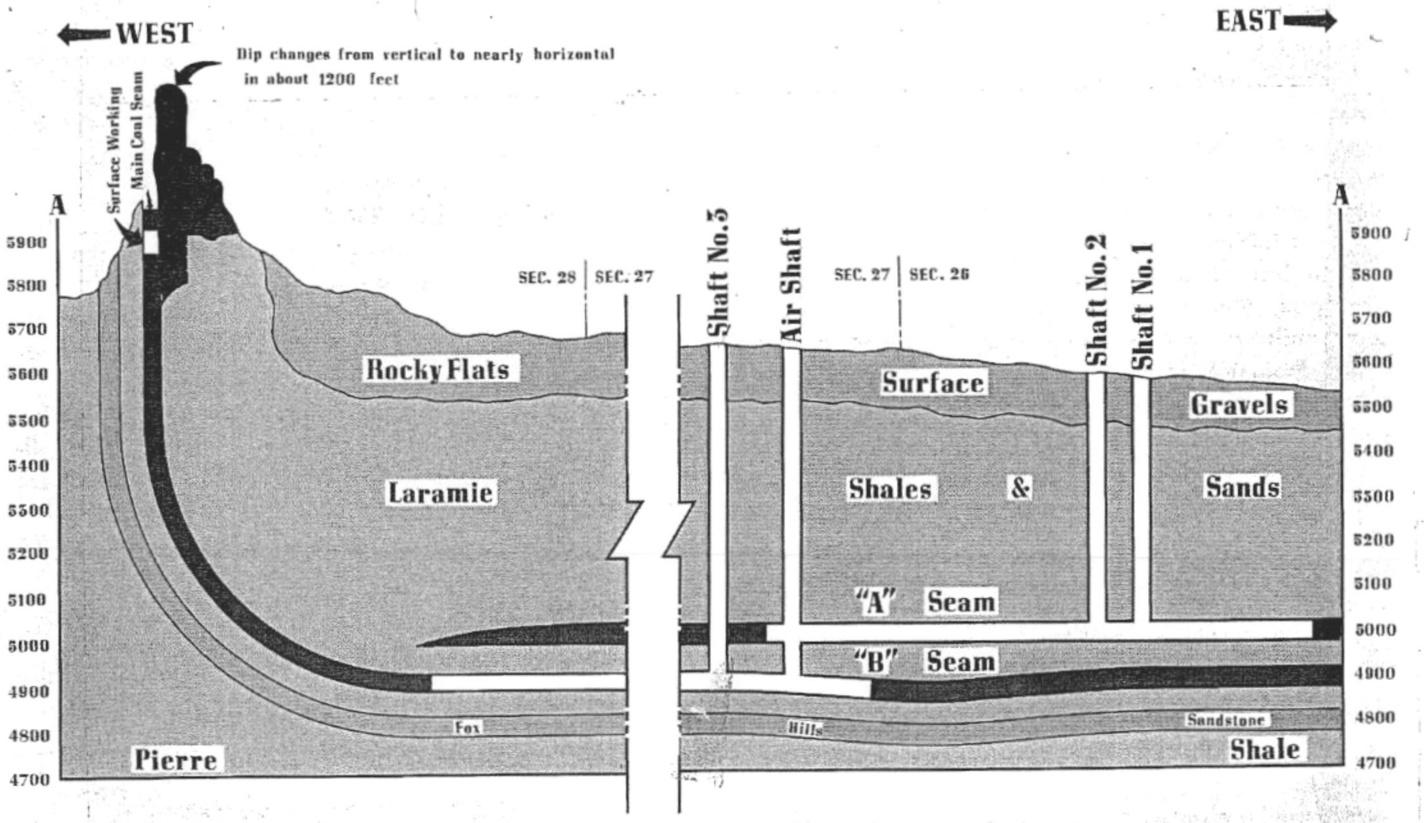
We are now in the process of reducing our "unaccounted for" gas to a level which can be tolerated by the auditors.

Bibliography

Katz, Donald L., et al, 1959, Handbook of Natural Gas Engineering: 802 p., New York, McGraw-Hill Book Company.

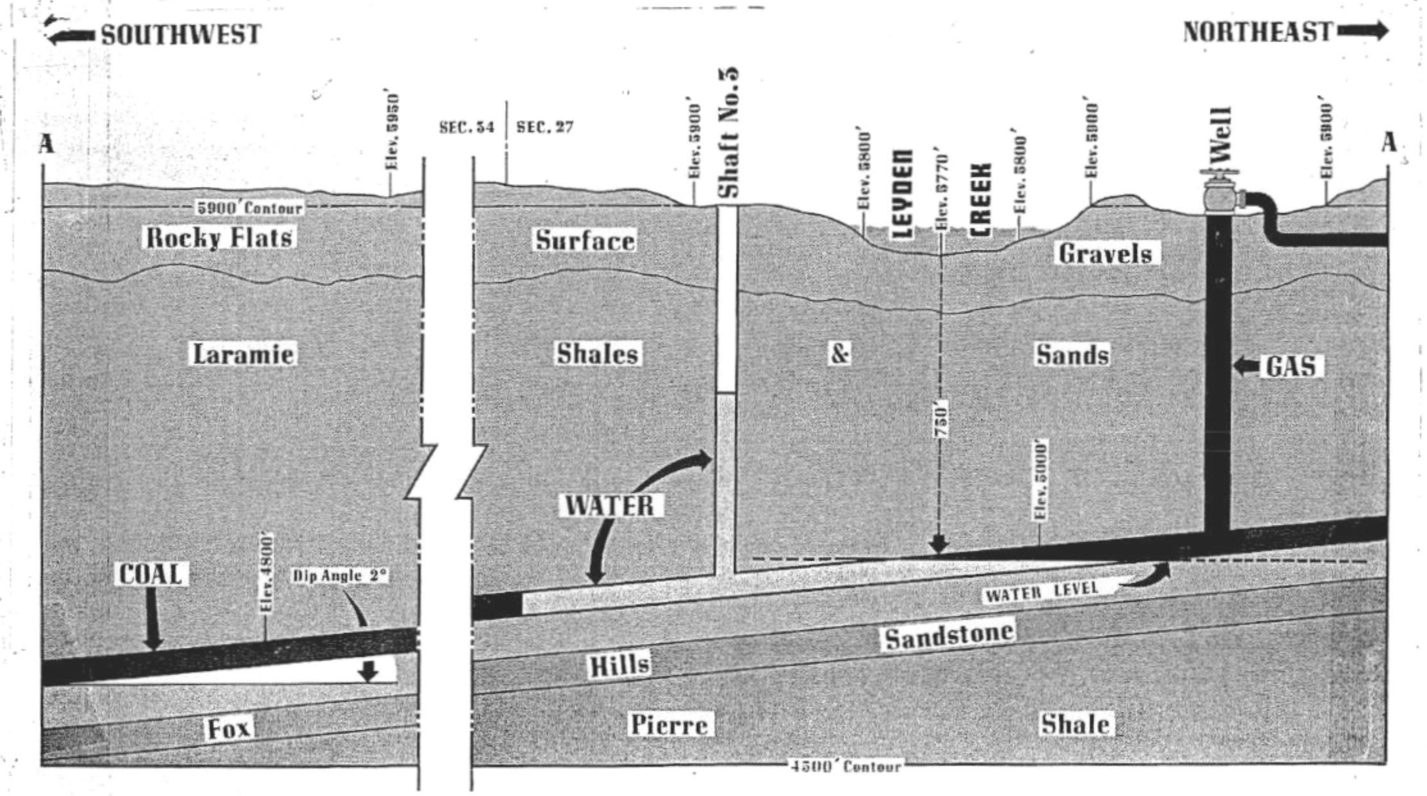
Kelly, Robert E., 1963, Cavern Storage of Natural Gas: 8 p., Public Service Company of Colorado.

Figure 1



SIMPLIFIED EAST-WEST SECTION
THROUGH LEYDEN LIGNITE MINE

Figure 2



DIP SECTION TO SHOW POSITION OF THE LEYDEN LIGNITE SEAM

PSC 039584

Figure 3

TYPICAL PRESSURE DECLINE EQUATION

Leyden Gas Storage Project

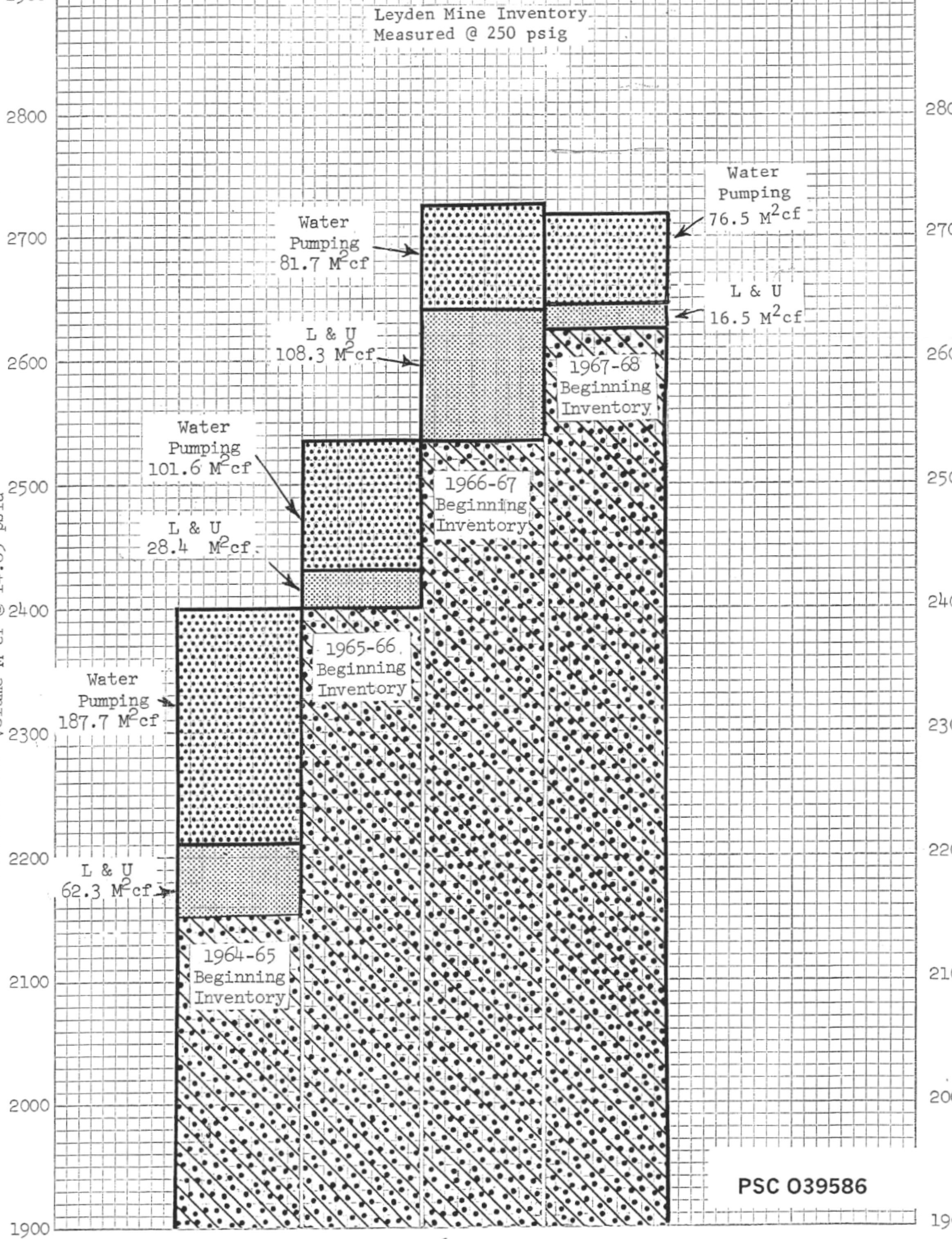
Pressure Range	Injection	Withdrawal
High (250 psig)	X = 6737 Y	X = 6049 Y
Low (100 psig)	X = 5283 Y	X = 7914 Y

Where:

X = remaining volume (MCF)

Y = pressure ($\text{psia}/_{z}$)

Figure 4


Leyden Mine Inventory
Measured @ 250 psig
Volume M²cf @ 14.65 psia
2900
2800
2700
2600
2500
2400
2300
2200
2100
2000
1900
Water Pumping 187.7 M²cf
L & U 62.3 M²cf
1964-65 Beginning Inventory
Water Pumping 101.6 M²cf
L & U 28.4 M²cf
1965-66 Beginning Inventory
Water Pumping 81.7 M²cf
L & U 108.3 M²cf
1966-67 Beginning Inventory
Water Pumping 76.5 M²cf
L & U 16.5 M²cf
1967-68 Beginning Inventory

February 1, 1967

H. A. Emery, Supervisor Planning Section   Gas Engineering

L. W. Brown, Market & Supply Engineer   Gas Engineering

Leyden Mine Storage Volume

Introduction

This memo outlines the volume calculations which are made at the request of Arthur Young and Company concerning the volume of gas in storage at Leyden Mine on December 31, 1966 at a cavern pressure of 209.9 psig or 233.54 psia bottom hole pressure.
212.3   239.25

Calculations

Maximum Void: The records of the Colorado State and Mine Inspector show that a total of 5,941,720 tons of coal were produced from Leyden Mine during its operating life. Density tests on samples of coal from the Leyden seam show an average density of 84.9# per cubic feet.

Therefore, $\frac{5,941,720 \text{ tons} \times 2000\#/\text{ton}}{84.9\#/\text{cu. ft.}} = 140 \ M^2\text{cf of void}$

Available Void: The available void in Leyden Mine is somewhat less than 140 M^2cf due to subsidence and water encroachment in the cavern. Pressure-volume tests conducted during the summer of 1965 indicate that the void may be as high as 114.2 M^2cf.

Added Void: After the 1966 withdrawal test 29,008,020 gallons of water were pumped from the mine, which would add 3.9 M^2cf to the above available void as follows:

$\frac{29,008,020 \text{ gal.}}{7.48 \text{ gal./cu.ft.}} = 3.9 \ M^2\text{cf of void}$ 116.2 / 3.9 / 120.1

Volume Calculations: Assuming an available void of 114.2 M^2cf plus an added void of 3.9 M^2cf due to water pumping gives 118.1 M^2cf.

120.1 x 239.25

Therefore, $118.1 \times \frac{233.54}{14.65} = 1,882 \ M^2\text{cf @ } 14.65 \text{ psia}$

Volume Inventory: Public Service Company records show that a net of 2,262,458 Mcf @ 14.65 has been injected into the mine as of December 31, 1966 at a pressure of 209.9 psig.

Therefore,		2,262 M^2cf	2262
	less	1,882 M^2cf	1961
	L & U gas	380 M^2cf	301

PSC 039587

February 1, 1967

Leyden Storage Volume - page 2

Remarks:

It should be noted that the above L & U increases monthly at high cavern pressures indicating that gas is being forced into thief formations; however, our 1966 pressure-volume tests show that most of this gas may be recovered at low cavern pressures.

L. W. Brown
Market & Supply Engineer

LWB:hp

FORM 850-22-0058

INTER-DEPARTMENT MEMO—PUBLIC SERVICE COMPANY OF COLORADO

DATE November 29, 1967

TO T. A. Jost, Property Accountant — Property Accounting (DEPARTMENT OR DIVISION)

FROM L. W. Brown, Market and Supply Engineer — Gas Engineering (DEPARTMENT OR DIVISION)

ATTN.

SUBJ. Gas in Storage in Leyden Mine

As a result of our 1967 testing program at Leyden Mine, we have been able to substantially reduce the amount of L & U gas in the cavern.

It is recommended that we do not charge off any Leyden gas during 1967 to the Lost and Unaccounted gas account.

LWBrown

L. W. Brown
Market and Supply Engineer

NOTED: W. A. Emery

LWB:kdk

cc: Merrill Stover
G. Paul Cook
Sam Miller

PSC 039589

FORM 850-22-0058

INTER-DEPARTMENT MEMO—PUBLIC SERVICE COMPANY OF COLORADO

DATE February 1, 1966

TO Frank B. Fry, Manager — Gas Engineering (DEPARTMENT OR DIVISION)

FROM L. W. Brown, Special Projects Engineer — Gas Engineering (DEPARTMENT OR DIVISION)

ATTN.

SUBJ. Leyden Mine Storage Volume

Introduction:

This memo outlines the volume calculations which are made at the request of Arthur Young and Company concerning the volume of gas in storage at Leyden Mine on December 31, 1965 at a cavern pressure of 250.7 psig or 278.04 psia bottom hole pressure.

Calculations:

Maximum Void: The records of the Colorado State Coal Mine Inspector show that a total of 5,941,720 tons of coal were produced from Leyden Mine during its operating life. Density tests on samples of coal from the Leyden seam show an average density of 84.9#/cu. ft.

Therefore, $\frac{5,941,720 \times 2,000\#/\text{ton}}{84.9\#/\text{cu. ft.}} = 140\ M^2cf$ of void

Available Void: The available void in Leyden Mine is somewhat less than 140 M^2cf due to subsidence and water encroachment in the cavern. Injection-withdrawal tests conducted during 1965 indicated the void to be in the neighborhood of 97 to 105 M^2cf.

Added Void: After the 1965 injection-withdrawal tests, 41,202,000 gallons of water were pumped from the mine, which would add to the above available void.

Therefore, $\frac{41,202,000\ \text{cu. ft.}}{7.48\ \text{gal./cu. ft.}} = 5.5\ M^2cf$ of void

Volume Calculations: Assuming an available void of 105 M^2cf plus an added void of 5.5 M^2cf due to pumping gives 110.5 cu. ft.

Therefore, $110.5 \times \frac{\overset{281.34}{278.04}}{14.65} = \overset{2122}{2,100}\ M^2cf$ @ 14.65 psia

Volume Inventory: Public Service Company records show that a net of 2,374 M^2cf has been injected into the mine as of December 31, 1965.

Therefore,

	2,374 M^2cf	2374
less	2,100 M^2cf	2122
L & U gas	274 M^2cf	252

PSC 039590

FORM 850-22-0058

INTER-DEPARTMENT MEMO—PUBLIC SERVICE COMPANY OF COLORADO

DATE February 1, 1966

TO ______ DEPARTMENT OR DIVISION

FROM ______ DEPARTMENT OR DIVISION

ATTN. ______

SUBJ. Leyden Mine Storage Volume - page 2

Remarks:

It should be noted that the 1965 injection-withdrawal tests were based on readily recoverable gas volumes and that the above 274 M^2cf may be permanently lost to thief formations. Additional testing at Leyden Mine during 1966 should help to determine whether or not this gas may be recovered.

LWBrown
L. W. Brown
Special Projects Engineer

LWB:hp

Concurrence:

Otto Bunning
System Planning Engineer

PSC 039591

at 18 - 250 psg
@ 13 - 250 psg
Inj - 229,582 MCF

3 mo) 229,582 = 76500 MCF/mo

76,500 MCF/mo
5 mo/yr
382,500 MCF/yr

@ 250 psig, Vol = 18.2 M^2CF
@ 14.65 psia

As of Dec 31, 1965, metered gas into Leyden was 2,374 M^2CF @ 14.65

+150, M^2CF charged to L&K

a total of 2,524 M^2CF

∴ L&K total (since inception)

2524
- 1870
654, M^2CF

[signature]

PSC 039592

December 29, 1964

T. A. Jost | Property Accounting

G. Paul Cook | Gas Engineering

Adjustment of Gas Volume in Storage at Leyden

This memo is to advise you that we have been unable to arrive at any definite loss of gas from Leyden and recommend that the volume in storage not be adjusted at this time.

We have taken all of the data for 1963 and 1964 and computed the volume that should be in storage by several methods. The results do not correlate with each other or with the measured volume in storage.

We will continue to pursue this problem and will advise you when we feel that we have determined an accurate adjustment figure.

G. Paul Cook
Special Projects Engineer

GPC:hp

Approval:

R. E. K
R. E. Kelly
Manager of Gas Engineering

PSC 039593

Jary Fin File

(Mtg. Agencies)

Box 77

REVIEW OF VERIFICATION OF INVENTORY

Highlights of all reports and pertinent data for the period 1952 through 1961 that was gathered by the Sub-committee on Verifying Inventory under Harry Hoover during his term as chairman, 1960-61.

Committee on Underground Storage: Re:
A Standard Procedure to Determine
Actual Gas in Storage

Sub committee on Verifying Inventory

81% of the companies measure gas in and out of storage in accordance with AGA Measurement Report #3.

All companies subtract from inventories "Loss and Use" gas. These are as follows:

1. Gas loss due to line leakage.
2. Gas loss due to purging lines.
3. Gas loss due to blowing drips.
4. Gas loss due to blowing and swabbing drips.
5. Gas loss due to well leakage.
6. Gas loss due to well repairs.
7. Gas used to make well repairs.
8. Gas used by customers supplied from storage system.
9. Gas loss due to blowing well during well completion.
10. Gas used as fuel during drilling.

Various Methods of Verifying Inventory

I. At the close of injection season, approximately November 1 each year, an individual shut-in well head pressure is taken with dead weight testers at each well every 24 hours until the pressure has stabilized across the entire field. From previous operating experience, the volume per pound pressure has been established. From this the volume of gas in storage is calculated.

This is then compared with volume of gas in storage as a result of metering in and out after all losses have been subtracted.

PSC 039596

If calculated volume is less than the metered volume, then it is assumed that a loss has occurred and steps are immediately taken to determine cause of loss and correct the condition.

II. From the beginning of the original "output" cycle the volume of gas removed was very accurately accounted for and from time to time shut-in pressures were recorded. This procedure made it possible to get a ratio between "volume" and "pressure drop" which is used to calculate the change in pressure due to gas "stored" or "withdrawn" in a designated period. Thus, a means of determining the storage gas inventory was arrived at.

It is believed by us that in order to verify the inventory another method of obtaining a pressure to compare with the calculated pressure is necessary. In order to arrive at a pressure independent of the calculated pressure twice, annually, the fields are shut-in for a three weeks period and shut-in pressures are recorded for each well. The average shut-in pressure is then computed and compared with the calculated pressure. If the two pressures are comparable within practical limits it is believed that the inventory is correct.

III. In addition to the measurement of all gas into and out of storage, we have attempted to take shut-in pressures of the wells in each storage project twice each year. Once at what is considered to be the end of the input period and the other test at the end of the output period. Iso-Baric maps are then made from the well pressures taken and a weighted average pressure of the pool arrived at for each input and output period. This average pressure and the volume of gas per pound rise or fall enables us to make a check against the volume of gas in each pool as shown on the inventory.

IV. The problem of verifying the gas in storage of the underground gas storage system of the Company both from an accounting and operating standpoint is as follows: Throughout the Company's storage system 7-day pressure recording gauges are maintained at each individual well (input and output wells). Each year we have experienced a period of inactivity at which time neither gas is being injected nor withdrawn, thus giving sufficient time to obtain a rock pressure which can be checked against previous corresponding rock pressures and volumes. Actually rock pressures and volumes are checked against an established so-called base curve which has been constructed on data obtained during the initial storage years; namely, a curve plotted on total gas placed in storage with corresponding shut in rock pressures, to or approximately to, the maximum rock pressure at which storage pools are to be operated, and by accounting for loss of gas during an input and output cycle, the base curve should check each succeeding year's cycle.

PSC 039598

V. It is our practice to compare these metered inventories and actual pressures from year to year so that we might assure ourselves that gas has not been lost due to migration in the storage sand or by escape to thief sands. This comparison is determined by gas per pound studies. In a calculation such as this, the pressure is the critical factor and the well pressures are determined by using the weighted average pressure method. By this method pressures are contoured on pool area maps and the various pressure areas determined by planimeter. Upon calculation of weighted average pressure this figure is divided into the inventory and the gas per pound calculated. It is obvious that any excessive loss of gas would cause the gas per pound figure to steadily increase over a period of time. It has been found that the most reliable pressures are those available at the conclusion of the injection season after a seven day shut-in period.

VI. The various combinations to be derived from such classifications is almost innumerable, and the many and radically different types of reservoirs and their behavior as storage pools suggest that verifying storage inventory has no simple solution. No one method appears applicable in all cases.

PSC 039599

Our own company has favored the use of coning curves, to the extent possible, in determining reservoir loss, generally plotting on coordinate paper the book quantity of gas in storage as the ordinate and the observed reservoir pressure as the abscissa, and thus preparing graphs showing the record of successive annual storage cycles on the various pools.

The best points of comparison appear to be at the end of the input cycle and end of withdrawal cycle, where in each case it is desirable to permit reasonable stabilization of pressure before final pressure data are determined, since varying rates and seasonal distribution of input and output affect the position of the curve. Generally also like portions of successive annual curves, where input and withdrawal rates for considerable periods are similar, give a fairly practical but less desirable basis for comparison.

Migration upward of the curve occurs in most instances in the early history of a reservoir due to the filling of the edges of the pool and the lower permeability portions of the sand; also the pushing back of bottom or edge water until relative stability is accomplished within the pressure range adopted for use year after year. The period of such curve migration varies with the degree and distribution of permeability and the extent and nature of water intrusion, and, as we all know, may continue for some years. After stability has been attained within the pressure range adopted, migration of the curve ceases, unless there is actual reservoir loss at the time, in which case it will still continue until such reservoir loss ceases. The migration of the curve may from the beginning be due to both filling of the remote parts of the reservoir and reservoir loss, which complicates the problem and use of the method, or, for that matter, any other method that might be used to determine storage inventory.

VII. Our method of verification is as follows: The volumes injected, less the volumes withdrawn, produced by oil wells, produced by migration, replacing fluid production (dependent on pressure in the formation) both on storage property and migration area, the volume in the migration area secondary gas cap (above pressure at start of migration) gives the net volume in storage.

Surface pressures of the storage wells are converted to bottomhole pressures by adding weight of column of gas and correcting for deviation. Bottomhole bomb runs determine the presence of any fluid that would alter the surface readings.

The volumes in storage plotted against corresponding bottomhole pressures gives us a hysterisis type loop series of curves that fall continuously within the same pattern. The axial line of this loop pattern being the equivalent of the volume-pressure relationship of an open container of comparable size.

The accuracy of these calculations is reflected by the curve. Migration was discovered by this method because we were progressively having larger volumes indicated to be in storage at equivalent pressures. Conversely, progressively smaller volumes in storage at equivalent pressures would be indicative of a shrinking reservoir as would be the case if active high head edge waters were present.

Two viewpoints for the solution of the problem of storage inventory verification have developed:

1. Pressure-volume relationship, per se, through the development of some kind of mathematical formula which will reduce to a common denominator, the many variables of different storage reservoirs.

2. The recorded orifice meter volumes, accepted by the industry, properly corrected for known (necessary or unavoidable) "loss and use" gas.

Proponents of the first of these viewpoints are, for the most part, prone to oversimplification of the problem by reason of non-operating experience and background. It is the opinion of some storage operating people that the use of pressure-volume relationship as an accurate check of metered volumes of gas in storage is of doubtful value for the following reasons:

1. The use of the metered volumes in pressure-volume calculations as proof of the unreliability of the same metered volumes is not an accepted mathematical practice.

2. The necessary variation in the manner storage reservoirs are operated from season to season could cause wide variation in observed rock pressures for comparable stored volumes. (This is a problem of pressure stabilization time.)

PSC 039602

3. The fact that the many unknown physical properties

of a storage reservoir must by their very nature, remain forever a mystery. Some of these unknowns are - the true areal extent of the reservoir, the thickness of the sand and its "pay" section between wells, the exact values of porosity and permeability, the degree of liquid saturation of the reservoir, the rate of progress, if any, of secondary depositional processes, and the question of at what pressure differential in reservoirs in so-called capillary control, does certain portions of unknown size and shape become useful for the storage of gas. The assumption of values for these unknowns in any formulae devised to calculate storage inventory allows for the introduction of great errors.

4. Where gas is metered into groups of storage wells the volume of gas stored in each well is not known, so it is impossible to weight the rock pressure of individual wells into the average rock pressure according to the volume of gas stored in each well. The arithmetic average of the rock pressure of such a group of wells is not necessarily a true reflection of the total volume (stored gas plus native gas reserves).

Those in the industry utilizing the method described by the second viewpoint contend that the orifice meter is accepted as the "cash register" of the gas business. From the producing gas well to the domestic customer's curb box (usually hundreds of miles apart) gas is sold and purchased, in some instances many different times, on the basis of recorded orifice meter chart data, which is corrected for temperature, gravity, deviation from Boyles Law, etc.

In the operation of an underground storage program the additional corrections made for "loss and use" gas, (which is in most cases necessary and in all cases unavoidable) are not made to correct the proved accuracy of the orifice meters but as an adjustment of the accurately metered volumes known as, the balance remaining in storage. This obviously is a necessary adjustment, since any gas lost or used after measurement into storage or before measurement from storage is chargeable to the balance remaining in storage or inventory.

Rock pressure tests are considered to be an important tool to be utilized in the refinement and revision of storage estimates concerning storage capacity and deliverability, as well as to indicate the need for, and the best location of additional wells, by showing the path of gas migration within the storage reservoir. In additon, such pressure studies are of value in the discovery of one or two of the dozen or more potential sources of "losses" which must be accounted for as "loss and use" gas.

In effect, this second viewpoint places the sole responsibility for the determination of the amount of storage losses squarely upon the engineering, geological and operating personnel. This group of operating people are usually responsible for the original selection of reservoirs to be utilized for storage purposes, most familiar with the native production, and storage history, and best qualified to evaluate the many factors involved in the determination of all storage "loss and use" volumes of gas to be reported for proper accounting.

VIII. For inventory control purposes, simple coning curve graphs, plotted on coordinate paper, are used. Gas in storage (MCF) is shown as the ordinate against which is plotted wellhead reservoir pressure (pounds) as the abscissa. One or more annual cycles may be shown on a single graph, each such cycle consisting of an input curve and its companion withdrawal curve.

PSC 039605

The brief discussion of the method given below, generalized and somewhat idealized, is based on our experience in its use in connection with small reservoirs originally containing dry gas. The method has been found to be satisfactory in the case of high fairly even permeability pools, and in low fairly even permeability pools after the latter have become stabilized within the maximum pressure range of use.

Obviously, if the method were applied to gas stored in a tank, empty at the start, and then filled with gas to some pressure, say 100 pounds, and the gas subsequently withdrawn, the quantities accurately measured in and out, pressures observed at say 10 pound intervals, and measured quantities of gas then in the tank calculated at each such observed pressure point, the plotted results would show a straight line; (Fig. 1) since the reservoir would be a single open space with practically immediate adjustment of pressure throughout as gas was injected and withdrawn.

When a reservoir rock is substituted for the tank, however, the effective reservoir becomes a complex maze of small connected spaces of irregular shape and size, and pressure-volume adjustments throughout the reservoir take place more slowly. The input and withdrawal curves plotted in the above mentioned manner, both depart from the straight line and show a coning curve, with the degree of departure from the normal curve or straight line depending on the permeability of the reservoir. The lower the permeability, the greater the departure from the normal curve.

In the case of a pool where high even permeability exists, and gas is injected and withdrawn at a reasonably even rate, such a curve appears as shown in Figure 2. As drawn, such curve indicates no gas loss from the reservoir, since the output curve returns properly in each cycle to the average curve (straight line) which extends through the zero Q and P point on the graph, and each succeeding input curve follows the pattern previously established, except the forepart of the first.

However, in the case of a high even permeability pool, where the output curve fails to return to the normal curve, loss of gas is both apparent and actual; (Figure 3) and the approximate magnitude of the loss is indicated on the Q scale at point (a). Should such loss continue, the curves representing successive annual cycles will migrate upward in the pattern of Figure 4; showing on scale Q the approximate annual loss for each successive cycle; and such migration will continue indefinitely until the cause of loss is removed.

In the case of a low fairly even permeability pool, coning curves plotted in a similar manner will fail to close in the first and possibly several succeeding cycles, thus indicating apparent loss which may not be actual. A typical case is shown in Figure 5. In this case there was apparent loss during the first four annual cycles, the quantity of such loss decreasing in each succeeding cycle, until in the fifth the coning curve closed, showing no apparent loss. In this instance it is reasonable to assume that there has been no actual loss of gas from the commencement of the operation, but instead the building up of a cushion required in the low permeability reservoir to stabilize behavior within the pressure range shown.

In such case, where there is no actual gas loss, a graph prepared on coordinate paper, on which time is plotted against the quantity of gas in storage per pound reservoir pressure for some pressure common to the several annual cycles (1) near the beginning of each input cycle and (2) near the beginning of each withdrawal cycle will appear as in Figure 6.

Should these curves fail to flatten in the manner shown, gas loss not only apparent, but actual, is indicated.

Other cases, depending on the degree of permeability, may fall between the two shown; or may fall beyond the second. In general, it may be said that, other conditions being equal, the lower the permeability, the longer will be the time required to fill the more remote portions of the reservoir and effect stability of behavior of the pressure volume relationship.

Where leakage has been suspected or known to exist in a reservoir, we have in a few instances shut in all wells in the pool at the end of a withdrawal season, disconnecting the wells from the pipeline to avoid any possible leakage at the well, and have taken pressures on each well at intervals of a few days. The total time required each day to take the pressures of all wells in a pool with the same dead weight gauge has been less than two hours, so that each set of results might practically be considered as taken simultaneously. Each group of pressures, corrected for variations in atmospheric pressure, has been shown on a separate base map of the pool and the pressures contoured. In addition to these maps, others have been prepared showing changes in pressure from one observation date to the next, or for some longer time interval. Such maps have been effective in pinpointing leakage within the reservoir area.

We have not developed any special forms for reporting gas blown from wells or otherwise lost in the field, but have depended on informal records of such loss as has been known to occur, based on estimates of quantity.

We have had no difficulty in satisfying auditors or F.P.C. in connection with verification of storage inventory, supported by the engineering data periodically prepared, generally in the manner above discussed.

For proper inventory control, we believe that in addition to correction for specific gravity, corrections for temperature and supercompressibility should of necessity be applied to the quantities of gas measured into and out of storage. Failure to make such corrections, particularly that for temperature, may in time result in the accumulation of considerable apparent loss which actually is gas measurement discrepancy.

IX. It is certainly true that pressures observed at the wells reflect the volume of gas in a storage reservoir, and it is standard practice in our operations for both "internal" and "external" Auditors to spot check rock pressure tests in the field at the time of maximum volume in storage in the Fall, and again in the Spring, when volumes and pressures are at the annual low point. These pressure tests are made at the well-head of each well with a bourdon tube type spring test gauge which has been calibrated with a dead-weight tester prior to each test period. All wells tested are active storage wells since no observation wells for pressure purposes are kept shut-in. In our early storage history (1937 to 1940) it was the policy to take pressures by this method for periods of shut-in of 24, 48 and 72 hours, but experience showed that changes from the 24 hour test were negligible in the 48 and 72 hours tests. In other words - apparent stabilization of well-head pressures of the individual wells was, for all practical purposes, attained by only a 24 hour shut-in. It also brought forcebly to our attention that storage operations had become such an important phase in balancing supply and demand over large areas, that the economic factor alone, more or less, required prolonged shut-down time of storage wells be held to a minimum.

In our storage operations these semi-annual pressure tests are considered as one of the "tools" to be utilized in the refinement of storage estimates of capacity and deliverability as well as the location of additional wells, etc., since these pressures are an indication of paths of stored gas migration within the storage reservoir. At this point in this summary, it should be made clear that in the request for another survey of procedures used in verification, the list of the type of information requested, item four "Observation of pressure for determining possible migration or leaks in the field" - the use of the word "migration" as synonymous with "leaks from the field" shows an appalling lack of understanding of the mechanics of underground storage. The only reason underground storage is possible is because of the phenomena of radial migration of gas from the well-bore at the sand face out into the reservoir during input and radial migration from the reservoir to the well-bore when the pressure differential is reversed, during output. Such misuse of the term "migration" can only further confuse accounting personnel.

The reservoirs utilized for storage by this company are irregular shaped, lenticular sand bodies which have contained their native gas for unknown eons of geologic time - 24 sub-projects in reservoir rocks of Silurian Age, and 1 sub-project in reservoir rock of Devonian Age. In each of these reservoirs the lateral migration of the original native gas (as well as presently stored gas) is confined by the "pinch-out" of the porous and permeable sandstone lens and is known to be isolated by the drilling of wells containing no sand, or in which the pressure history varied sufficiently from that of the storage reservoir to insure complete separation. Sufficient perimeter acreage is secured and charged to storage operations, and adjacent producing wells are controlled by our company in order to protect against any errors in judgment of pre-storage definition of areas.

Because the lateral migration of stored gas is confined by the lens-like nature of the reservoir in these "outliers" or "islands" of "Clinton" sandstone and it must be conceded that it is possible, in a very few instances, to mis-judge the actual extent of that sand body from available data; we allow for that possibility when storage experience so dictates, and enlarge the area to include any such well, adjusting capacity and deliverability estimates accordingly. From the above information it is plain to see that there is little or no possibility for reservoir leakage laterally.

The only other possible source of reservoir leakage then is vertically. Here again, in our operations, it has been observed that no such leakage has occurred. One proof lies in the fact that approximately one half of the storage wells now in use were drilled for storage purpose. In the drilling of approximately 500 wells from the surface to and through the storage reservoirs, (some after 15 years of storage experience) never, in even one instance, was storage gas, (determined by analysis) or storage pressure encountered in any shallower or deeper formation. This is sufficient proof to us that our storage reservoirs are "gas tight" for storage use up to and including a pressure equal to the maximum reservoir pressure present when the first original or native gas producing well was drilled. In none of our operations have maximum original pressures been exceeded. The only other source of reservoir leakage is the wells drilled for native gas production and plugged and abandoned before storage started. Subsurface leakage from this source has not been known to occur since the 500 wells drilled for storage have never encountered storage gas in any shallower formations. Surface losses to the atmosphere, if any had occurred, should be readily discovered by changes in vegetation in the vicinity of such a wlll site. This company has not made its policy to include the re-drilling and re-conditioning, or re-plugging of all abandoned wells in storage areas, but in a few instances, where part of the tubing or small size casing was abandoned in an old well, they have been drilled out, such material removed, the hole redrilled where necessary, the sand face cleaned up and the well re-equipped for storage use. In each such instance during cleaning our operations it has been found that no gas is present, and that it is only after extensive work with fresh water cleaning-up of the sand face that such wells respond and show signs of communicating with the storage reservoir.

This is believed due to the slow but continuous process of deposition of heavy hydrocarbon materials, salt crystals, mud, black brackish water, etc. near the face of the sand during the native production history from the radial flow of gas into the well-bore at ever decreasing pressure differential through the years of the life of such wells, plus the likelihood of cavings between the packer setting and the face of the producing formation, along with the probable seepage of water around the packer from prolific salt water bearing formations above.

From the foregoing discussion it is apparent that in the underground storage operations of this company there is no known underground loss of stored gas either to thief formations or to the atmosphere from plugged and abandoned wells.

PSC 039613

Many more reasonable and more easily understood facts are available to show those without operating experience that stored gas is recoverable. For instance, in one of our storage projects nearly one billion cubic feet of gas was stored, and during the ensuing output period all stored gas withdrawn, the wells transferred from storage to regular, and 390 million cubic feet of native gas withdrawn and sold. The following summer these wells were again transferred to storage use. Of course, the starting pressure when storage began was high enough in this instance to recover all stored gas in one output cycle, it would take proportionately longer periods of time to obtain the same result in reservoirs in which the cushion gas volumes were greater.

Another fact: in one storage sub-project with capacity for 6 billion cubic feet of stored gas at t op operating storage pressure, there has been stored a total of 30 billion cubic feet and withdrawal of 24 billion cubic feet over a period of 15 years, and the maximum volume of gas in storage last fall was 6 billion cubic feet (reasonably near top pressure) ready to deliver gas at a rate of 85 million cubic feet per day.

In the over-all picture since the inception of storage ope rations in the year 1936, through 1954, more than 300 billion cubic feet of gas was placed in storage, and during the same period more than 200 billion cubic feet has been delivered to markets. The remaining 100 billion now in storage is capable of delivering (through existing pipeline facilities), approximately one billion cubic feet of gas on the peak demand day of the current output cycle this winter. (1954-55)

The so-called "problem" of storage inventory verification really boils down to a problem of mutual understanding of the vagaries of storage reservoir phenomena.

The following applies to an aquifer type reservoir. This company is very new at gas storage in water filled sands. Our present thinking is to tie volume, as represented by the elevation of the gas-water contact, to density of the gas as represented by a well head pressure to be corrected to the elevation of the mid point of the gas bubble. Eight water level observation wells are planned to intersect the stored gas bubble at a distance averaging 3/4 miles apart.

We feel that a gas contract area of some 2,500 to 3,000 acres will not maintain a flat surface, definitely during injection or withdrawal and probably not after reasonable periods of shut-in. The water-level observation wells are planned to be cased through to total depth of known closure of the structure and perforated so as to always stand full of water. Water levels observed in these wells during injection and withdrawals are expected to yield useful information as to how the sand reservoir is responding to such use. A water level in the reservoir would be obtained by neutron logging. A few years of this type of history when correlated with net in and out volumes should eventually indentify a definite volume of gas in place for each foot of reservoir space.

We are just now starting a drilling program to provide ten input-production wells for __________ storage field. At the completion of these wells we expect to have our injection plant completed so that cushion gas can be started into the reservoir by May first. The observation well program would be provided after injection of gas has been assured.

The above represents our present thinking on a method to verify storage inventory. Thinking may change somewhat before actual accomplishment.

The following applies to reservoirs in general.
The objective of this sub-committee is to investigate the methods used and if possible to formulate a standard procedure for verification of underground storage inventory.

During the current year information was received from 31 companies operating 179 storage fields in the United States. A summary of this data is attached.

The sub-committee met September 19, 1955, in conjunction with the Kansas City meeting of the Committee on Underground Storage. At that time it was decided that there was not sufficient information available on the subject to formulate a standard procedure.

During the ensuing months a questionnaire requesting specific information on verification methods was prepared and distributed by the sub-committee. Forty-six operating companies were contacted. Of this number thirty-one returned completed questionnaires, four stated that they were not currently engaged in underground storage operations, and eleven failed to reply.

A detailed analysis of the completed questionnaires is presented as a part of this report. For each question a computation has been made of the number and percent of the thirty-one operators who replied in the affirmative, negative, or failed to reply. We feel that in most cases a failure to reply is equivalent to a negative answer although in some instances our questions were either poorly worded or did not lend themselves to a simple answer. PSC 039616

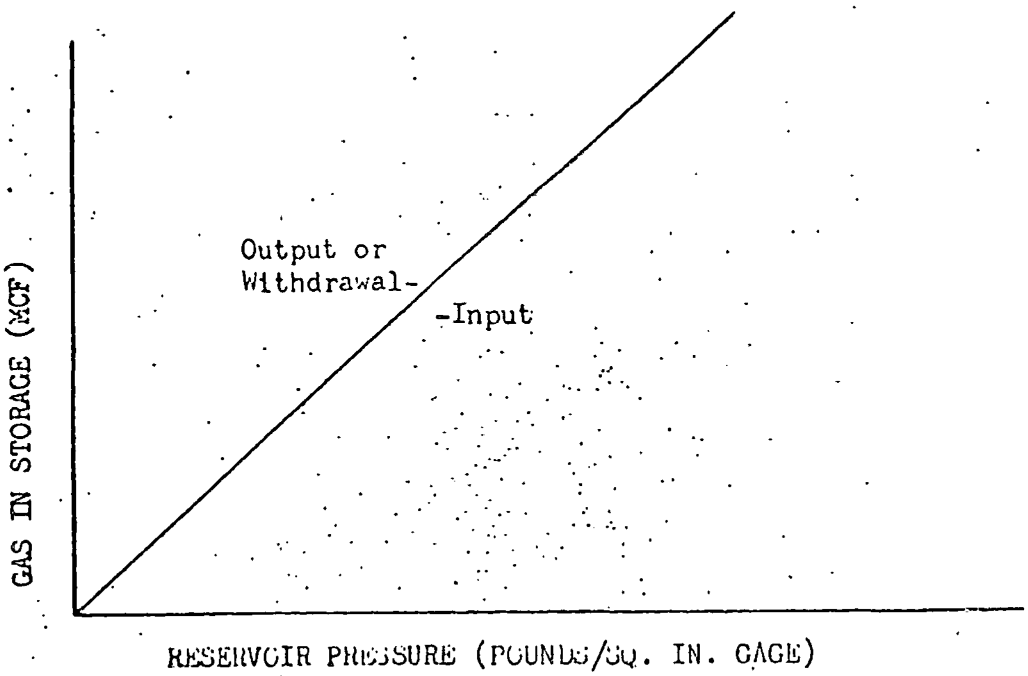
Listed below are a few of the significant points revealed by the questionnaire for interpretation.

1. More than 70% of the storage reservoirs currently in use are sand lenses which originally produced dry gas.

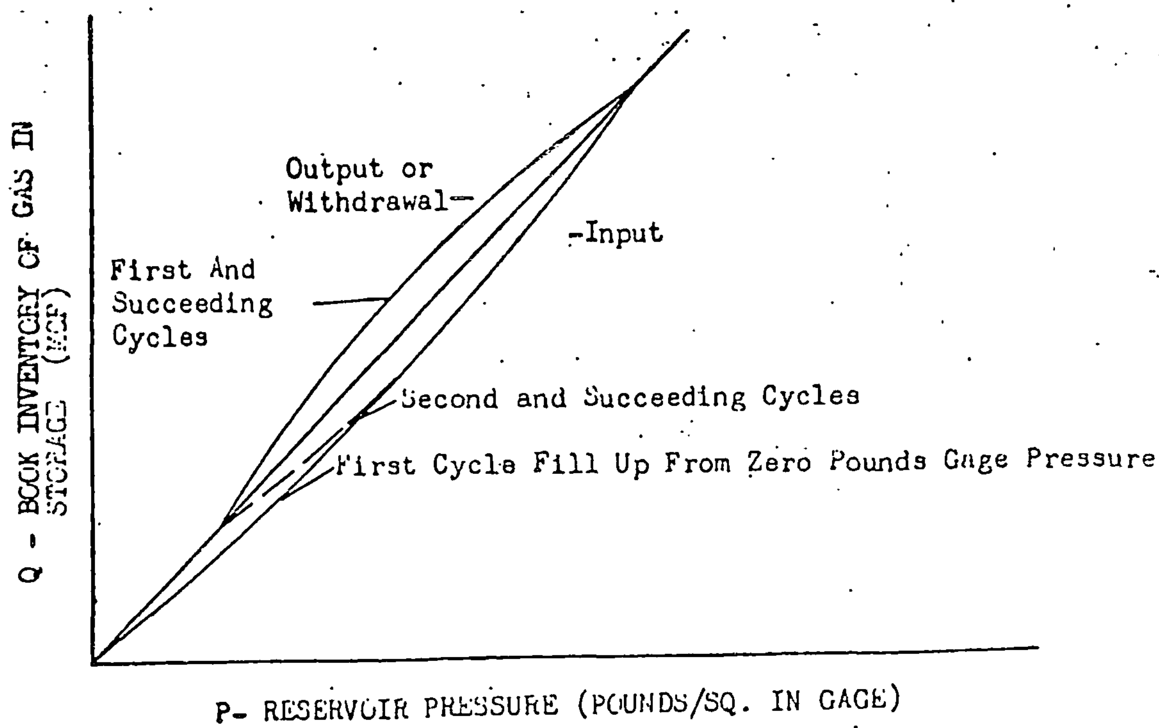
2. Practically all operators make corrections for specific gravity, temperature, and supercompressibility to volumes of gas metered into and out of storage.
3. Metered volumes are verified by reservoir calculations by 81% of the operators.
4. Present methods of inventory control are considered satisfactory by 61% of the operators.
5. Of the operators reporting 65% feel that a "standard procedure" for inventory verification would be beneficial to the industry as a whole.

Replies to the questionnaire were received from twenty-three people representing twenty-six companies. These companies control 144 storage fields containing 5775 wells.

PSC 039617



(Fig. 1)



(Fig. 2)

PSC 039618

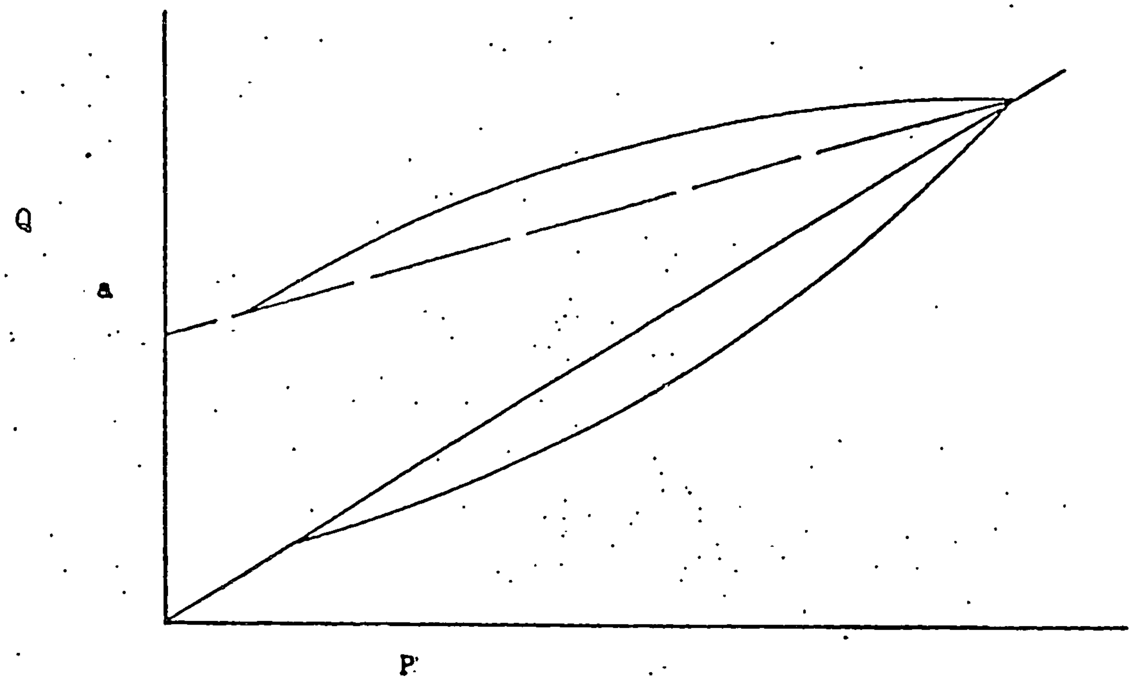


Fig. 3

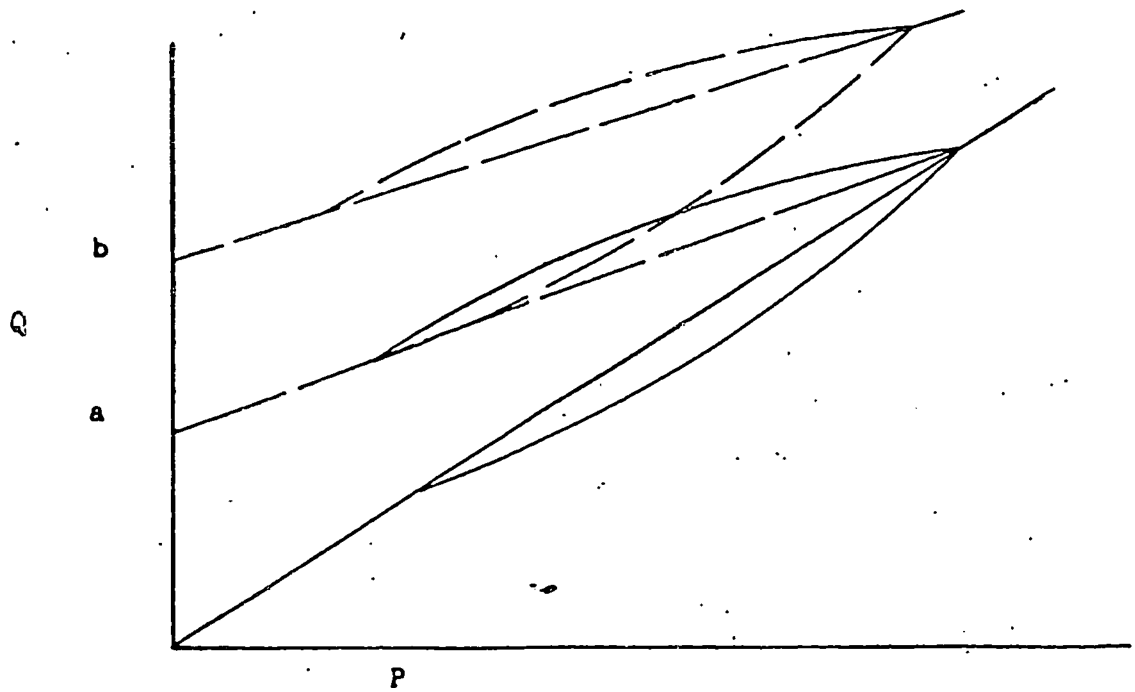


Fig. 4

PSC 039619

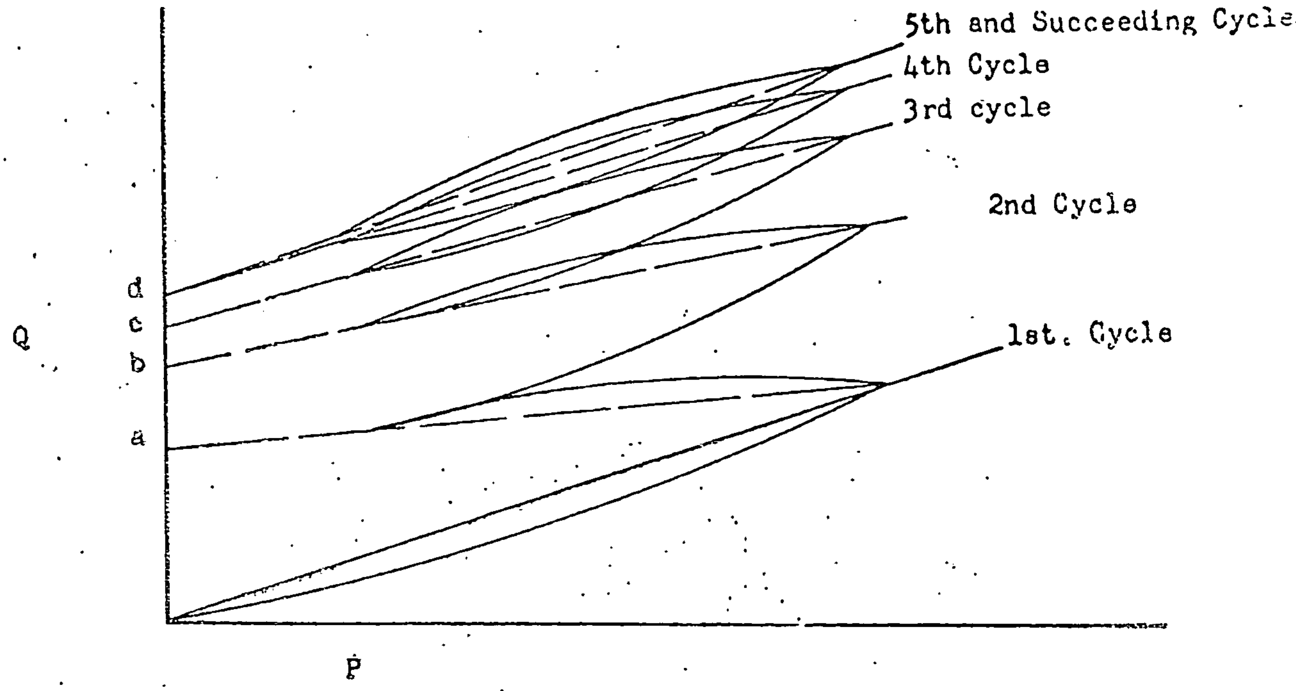

5th and Succeeding Cycle
4th Cycle
3rd cycle
2nd Cycle
1st. Cycle
d
c
b
a
Q
P

Fig. 5

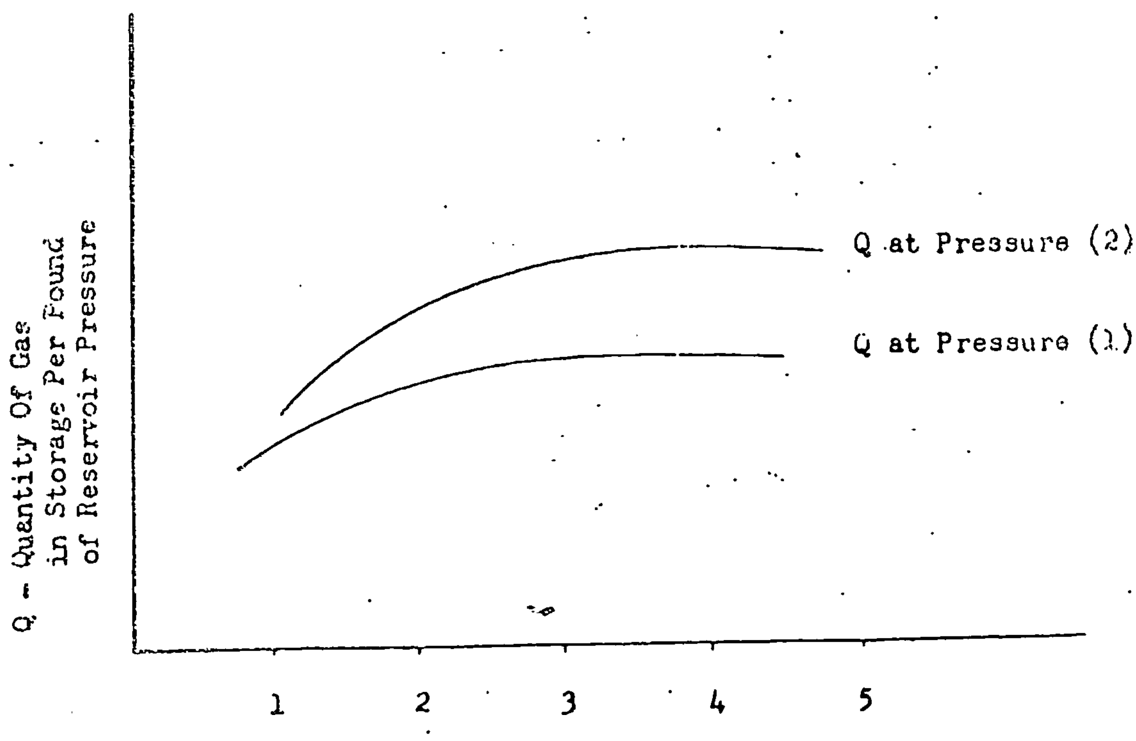

Q - Quantity Of Gas in Storage Per Pound of Reservoir Pressure
Q at Pressure (2)
Q at Pressure (1)
1
2
3
4
5
T - Annual Cycles

Fig. 6

Description of Storage Gas Inventory

A In your company, does the phrase "storage inventory" include

1 Only "working gas" (i.e. volumes stored and withdrawn each year)? 3

2 Working gas and cushion gas? 14 (Two repliers each have one field that falls in I-A-3)

3 Working gas, cushion gas and native gas? 6

4 Some other combination? None

a If so, please describe

II Sources of and Methods Used in Obtaining Pressure Data

A Do you obtain pressures at individual wells? 23 Yes If so, where obtained.

1 Wellhead 23 Yes If so: All wells 20 Some 3

2 Single well line 1 Yes If so: All wells - Some 1

3 Bottom hole 4 Yes If so: All wells 3 Some 1

4 If answer is affirmative for either 1 or 2, are the pressures corrected to bottom hole conditions? 12 Yes

B Do you obtain pressures from field lines (pressure source from more than one well as described on Page 1)? 8 Yes

1 If so, are pressures taken at one place only? 6. At a number of locations? 2

2 Are these pressures corrected to reservoir conditions? 1 Yes, 7 No

3 Is the practice of taking shut-in pressures on field lines to cover groups of wells or an entire field more or less a standard method rather than taking individual well pressures? 9 No

4 Are both methods used? 8 Yes

C Are shut-in pressures taken at regularly scheduled intervals? 18 Yes, 4 No, 1 No answer

1 What is the normal frequency and at what times in the year? 13 semi annual 1 annual, 4 various

PSC 039621

D Do you have standard lengths of time that shut-in pressures are taken?

16 Yes, 6 No, 1 no answer

1 What is the length of time or range in times that may be used?

Various - refer to detail sheet

E Do you have permanent pressure observation wells from which the shut-in reservoir pressure is continuously observed? 17 Yes, 4 No, 2 no answer

III Uses and Applications of the Pressure Data Obtained

A What is your primary use of this data?

1 As a verification method 11 Yes, 4 No, 8 no answer

2 As an approximate inventory check 14 Yes, 9 no answer

3 In reservoir engineering studies 18 Yes, 5 no answer

a Do you make any correlation of pressures with gas inventories?

18 Yes, 5 no answer

b Other? 11 Yes, 1 No, 11 no answer

(1) Describe Various - refer to detail sheet

B What pressures are used?

1 Are well pressures alone used? 16 Yes, 4 No, 3 no answer

a Are well pressures averaged by any method? 18 Yes, 3 No, 2 no answer

(1) Describe method used 9 Arithmetic, 6 Weighted,

4 Miscellaneous, 4 No Answer, Refer to detail sheet

2 Are field line pressures used in place of well pressures? 1 Yes

20 No, 2 No Answer

a If so, are these pressures averaged in any method? 3 No, 20 No Answer

(1) Describe method used Refer to detail sheet

3 If permanent pressure observation wells are used, are the pressures obtained used in the calculation of averaged pressures mentioned above? 12 Yes, 7 No, 4 No Answer

PSC 039622

a Are these observation well pressures used as a substitute for an "average" pressure as described above? 6 Yes, 11 No, 6 No Answer

(1) Is more than one well in a field used? 8 Yes, 3 No, 12 No Answer

(2) If more than one, are they averaged? 5 Yes, 2 No, 16 No Answer

4 Is any combination of the above pressures used? 6 Yes, 7 No, 10 No Answer

a Describe method used Refer to detail sheet

C Is there a noticeable variation in the pressure-volume relationship of any one of your storage reservoirs from year to year? 18 Yes, 3 No, 2 Miscellaneous

1 If so, do you attribute this to a change in reservoir size related to water movement? 13 Yes, 3 No, 7 No Answer Fluid removal? 4 Yes, 6 No, 13 No Answer

Time rate of injection or withdrawal 10 Yes, 1 No, 12 No Answer

Gas loss? 6 Yes, 7 No, 10 No Answer Other cause? Refer to detail sheet

2 Is storage inventory corrected for such variation? 7 Yes, 12 No, 4 No Answer

a If so, briefly describe how Refer to detail sheet

D Other uses of Pressure Data

1 If pressure data is collected primarily for uses other than pressure-volume studies, briefly describe source and uses of this data Refer to detail sheet

IV Uses of Temperature Data

A Are bottom-hole temperature corrections applied to your inventory calculations? 8 Yes, 15 No

1 How are these temperatures measured? Refer to detail sheet

2 How are they applied to your calculations? Refer to detail sheet

V Observation of Other Reservoir Fluids

A Are fluids other than gas observed from wells within or surrounding the area of the gas reservoir? 15 Yes, 7 No, 1 No Answer

PSC 039623

1 Would you consider the use of these wells for such a purpose a verification procedure? 2 Yes, 10 No, 11 No Answer

An approximate check of inventory? 3 Yes, 8 No, 12 No Answer

2 What fluids are observed? Refer to detail sheet

3 How are they observed? Refer to detail sheet

4 Why are they observed? Refer to detail sheet

VI Description of Reservoir

A Classification of Reservoir Type

1 Predominate Feature of Closure

Petrologic or stratigraphic 87 Structural 37 Combination 20

2 Predominate Fluids Native to the Reservoir

Oil 2 Oil and Gas 12 Gas 124 Water (Aquifers) 6

3 Maximum operating field pressure 60 - 3800 psig

4 Minimum operating field pressure 20 - 1980 psig

5 Maximum inventory volume at maximum pressure Maximum - 140,000 MMCF. Minimum - 50 MMCF. Total Capacity 1,650,000 MMCF.

6 Number of storage wells Maximum - 345. Minimum - 1. Total Wells - 5775

VII Source of Pressure Data

A Continuously Recorded Pressures

1 Pressures taken are:

Wellhead 64. Bottom Hole None Pipe Line 44

Note: If more than one of the above are taken, please indicate (W.H., B.H., or P.L.) which one is applicable when answering the questions below.

2 Type of pressure instrument

Bourdon Tube 75 Other (Specify) None

3 Recording location

At pressure source 84 Remote (Telemeter) None

PSC 039624

SUMM OF REPLIES TO 1956 QUESTIONNA

SUB-COMMITTEE ON INVENTORY VERIFICATION

UNDERGROUND STORAGE COMMITTEE

AMERICAN GAS ASSOCIATION

I. CHARACTERISTICS OF THE STORAGE RESERVOIR (Please indicate number in each category.)

Number and percent of the 179 fields in each category.

A. Type of trap - Dome 36 - 20.1% Lens 129 - 72.0% Other 14 - 7.9%

B. Lithology - Sand 159 - 88.8% Lime 17 - 9.5% Other 3 - 1%

C. History - Produced gas 167 - 93.3% Oil - Both 6 - 3.35% Water Sand 6 - 3.35%

D. Approximate initial reservoir pressures 100 - 3200#

II. METHODS OF INVENTORY CONTROL

Number and percent of the 31 storage operators who replied in the affirmative, negative, or failed to reply. (N. R. - No reply.)

A. METERED INVENTORY

1. Point of gas measurement

a. At individual wells Yes 9 - 29%; No 3 - 10%; N.R. 19 - 61%

b. By groups of wells Yes 6 - 19%; No 4 - 13%; N.R. 21 - 68%

c. At central point for entire storage unit Yes 20-65%; No 2-7%; N.R. 9-29%

d. By a combination of a, b or c Yes 9-29%; No 2-7%; N.R. 20-65%

2. Are the basic orifice factors from AGA Measurement Report No. 3 used for orifice meter measurements? Yes 25 - 81%; No 6 - 19%

If not what factors are used? 6 or 19% use either AGA Measurement Report #2 or a Meteric Metals Company bulletin.

3. Are the following corrections applied to metered volumes to compensate for the varying physical characteristics of natural gas?

a. Specific Gravity Yes 30 - 97%; No 1 - 3%

(Corrections are applied to volumes metered into and out of storage by all operators except two who correct only volumes to storage.)

A. METERED INVENTORY (CONTINUED)

b. Temperature Yes 30 - 97%; N.R. 1 - 3%

c. Supercompressibility Yes 28 - 90%; No 2 - 7%; N.R. 1 - 3%

d. Please list any other corrections of this type 2 or 7% of the 31 storage operators made additional corrections.

4. Are metered volumes corrected for unmetered gas used by company and pipe line leakage?

a. Farm Use Yes 16 - 52%; No 7 - 23%; N.R. 8 - 26%

b. Heater Use Yes 15 - 48%; No 9 - 29%; N.R. 7 - 23%

c. Servicing of wells and pipe lines Yes 26-84%; No 4-13%; N.R. 1-3%

d. Leakage from gathering lines and well casing Yes 9-29%; No 16-52% N.R. 6 - 19%

(1) Is leakage determination based on:

(a) % of metered volumes: Input: Yes 2-7%; No 3-10%; N.R. 26-84%

Withdrawal: Yes 0; No 3-10%; N.R. 28 -90%

Both: Yes 1 - 3%; No 2 - 7%; N.R. 28 - 90%

(b) Line pressure and total pipe surface area Yes 5-16%; No 2-7% N. R. 24 - 77%

(c) Other Yes 7 - 23%; No 1 - 3%; N.R. 23 - 74%

e. Other corrections of this type Yes 6 - 19%; N.R. 25 - 18%

B. CALCULATED INVENTORY

1. Are volumes in storage verified by reservoir calculations? Yes 25-81%; No 6-19%

2. How are the following determined?

a. Reservoir Pressure

(1) Is reservoir pressure observed under shut in conditions?

Yes 25 - 81%; No 6 - 19%

If so, is field shut in at: End of injection Yes 28-90%; No 2-7% N.R. 1 - 3%

End of withdrawal Yes 6 - 19%; N.R. 25 - 81%

Both Yes 25 - 81%; N.R. 6 - 19%

Other time Yes 8 - 26%; N.R. 23 - 74%

(2) If shut in pressures are used, what is the time allowed for shut in? - - -

(3) Are pressures taken at the end of the shut in period used?

Yes 28 - 90% N.R. 3 - 10%

(4) Is reservoir pressure during shut in period taken, continuously?

Continuously Yes 7 - 23%; N.R. 24 - 77%

Hourly Yes 1 - 3%; N.R. 30 - 97%

Daily Yes 15 - 48%; N.R. 16 - 52%

Weekly Yes 4 - 13%; N.R. 27 - 87%

Or other Yes 6 - 19%; N.R. 25 - 81%

(5) Are pressures weighted or averaged arithmetically? Weighted 8 - 26%; Ave. 19 - 61%; N.R. 4 - 13%

(6) If weighted average pressures are used, how are they obtained?

Map 4 - 13%; Other 5 - 16%; N.R. 22 - 71%

(7) Is reservoir pressure observed on shut in observation wells during storage operations? Yes 23 - 74%; No 3 - 10%; N.R. 5 - 16%

(a) If so, how many wells are used? - - - -

(b) If more than one observation well is used, is average pressure used?

Yes 12 - 39%; No 2 - 7%; N.R. 17 - 55%

Weighted average pressure Yes 4-13%; No 1-3%; N.R. 26-84%

Key observation well pressure Yes 6-19%; No 2-7%; N.R. 23-74%

(c) Is observation well pressure plotted against reservoir volume?

Yes 14 - 45%; No 7 - 23%; N.R. 10 - 32%

If so, is it plotted through several yearly cycles?

Yes 10-32%; N.R. 21 - 68%. Single cycle Yes 1-3%; N.R. 30-97%

Other Yes 1 - 3%; N.R. 30-97%

b. Reservoir Temperatures

(1) Are reservoir temperatures used for volume calculations?

Yes 9 - 29%; N.R. 19 - 61%

(2) How are reservoir temperatures determined?

BHB 6 - 19%; Other 4 - 13%; N.R. 21 - 68%

(3) Are weighted averages or arithmetically averaged temperatures used? Weighted 0; Ave. 6 - 19%; N.R. 25 - 81%

(4) If weighted average temperatures are used, how are they averaged? None used.

3. Are calculated volumes in storage corrected for supercompressibility?

Yes 13 - 42%; No 13 - 42%; N.R. 5 - 16%

If so, are supercompressibility factors based upon reservoir temperatures?

Yes 10 - 32%; No 2 - 7%; N.R. 19 - 61%

4. Do you find the pressure volume relationship of your storage reservoir to be reasonably constant? Yes 27 - 87%; No 1 - 3%; N.R. 3 - 10%

a. During field shut in period? Yes 21 - 68%; N.R. 10 -32%

b. During operations? Yes 15 - 48%; No 2 - 7%; N.R. 14 - 45%

5. In the reservoirs with which you work, would an abrupt change in this relationship under either 4a or 4b above indicate a loss of gas?

Yes 18 - 58%; No 6 - 19%; N.R. 7 - 23%

6. Do you consider reservoir pressure data, when used in conjunction with past reservoir performance, to be a reliable check on current metered volumes?

Yes 25 - 81%; No 4 - 13%; N.R. 2 - 7%

B. CALCULATED INVENTORY (CONTINUED)

7. Do you consider changing reservoir pore volume due to water ingress or egress? Yes 11 - 35%; No 17 - 55%; N.R. 3 - 10%

III. DO YOU FEEL THAT PRESENT METHODS OF INVENTORY CONTROL ARE SATISFACTORY?

Yes 19 - 61%; Qualified Yes 5 - 16%; No 5 - 16%; N.R. 2 - 7%

IV. PLEASE LIST ANY VERIFICATION PROBLEMS WHICH YOU FEEL THAT THIS SUB-COMMITTEE SHOULD INVESTIGATE Problems were suggested by 8 - 26% *

V. IN YOUR OPINION, WOULD A "STANDARD PROCEDURE" FOR INVENTORY VERIFICATION BE BENEFICIAL TO THE INDUSTRY AS A WHOLE? Yes 20 - 65%; No 6-19%; N.R. 5-16%

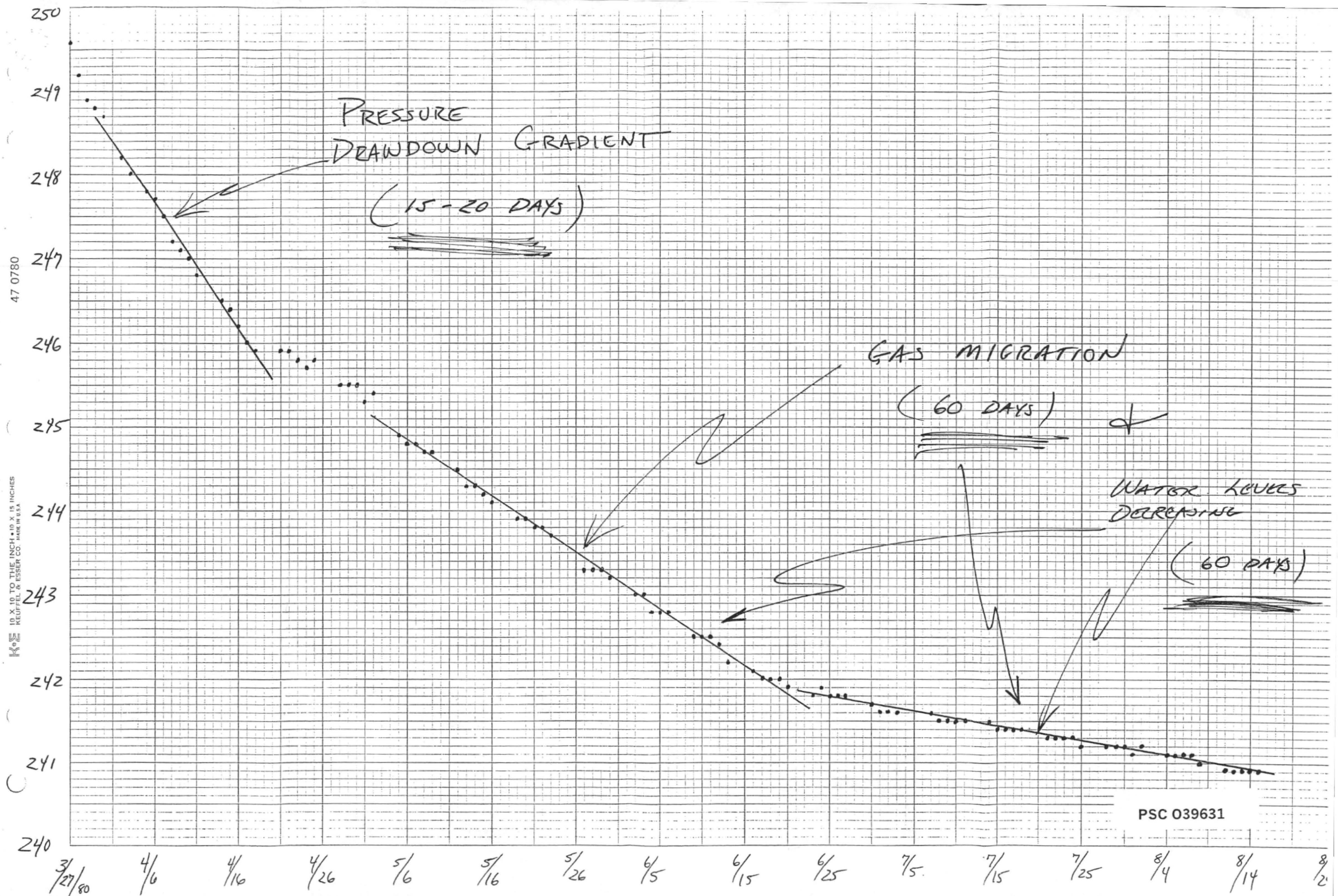
VI. DID YOU RECEIVE A COPY OF THE MATERIAL GATHERED BY THIS SUB-COMMITTEE IN 1955?

Yes 15-48%; No 13-42%; N.R. 3-10% IF NOT, WOULD YOU LIKE A COPY? Yes 13-42%

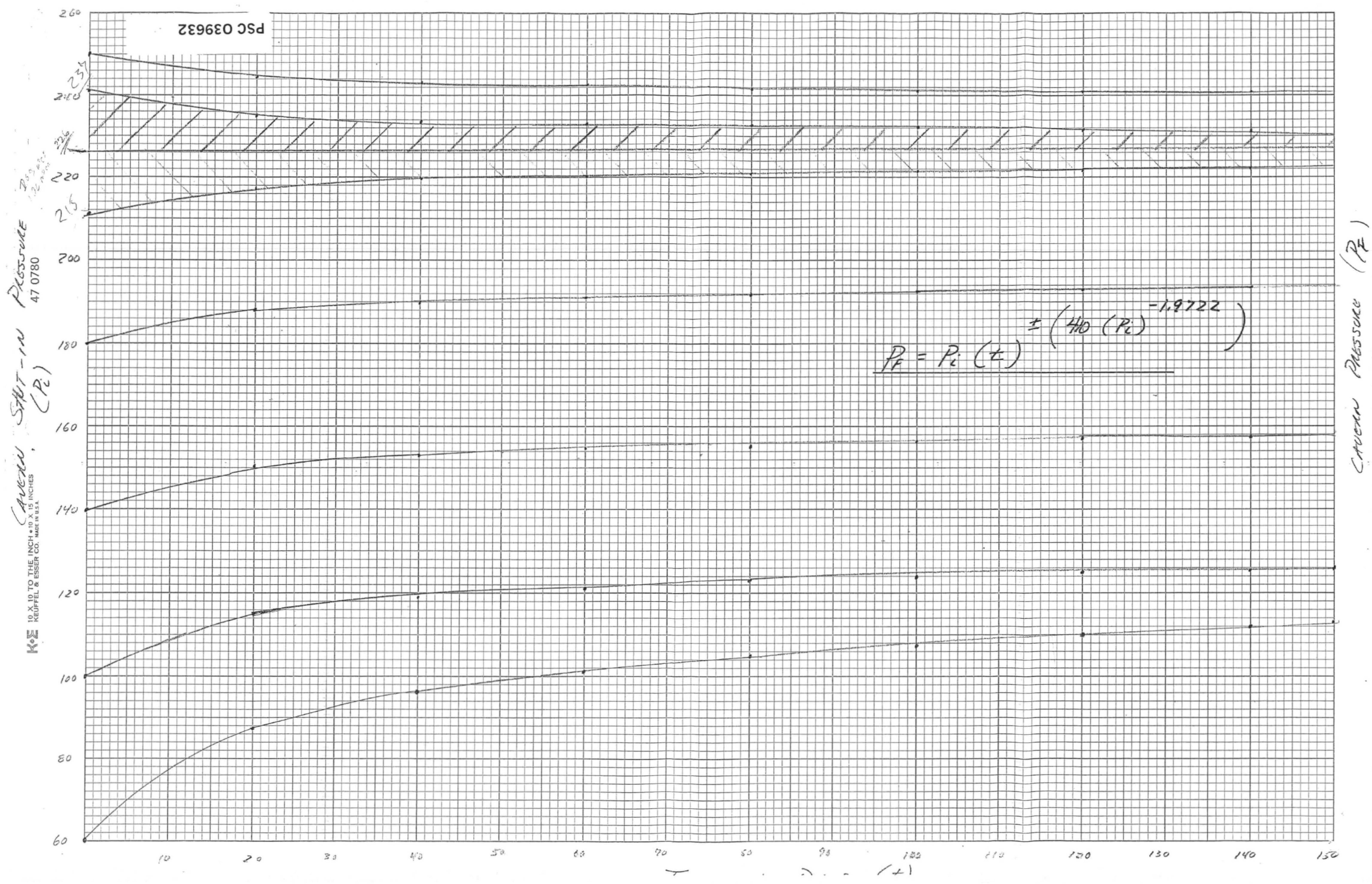
This material was sent to those requesting it.

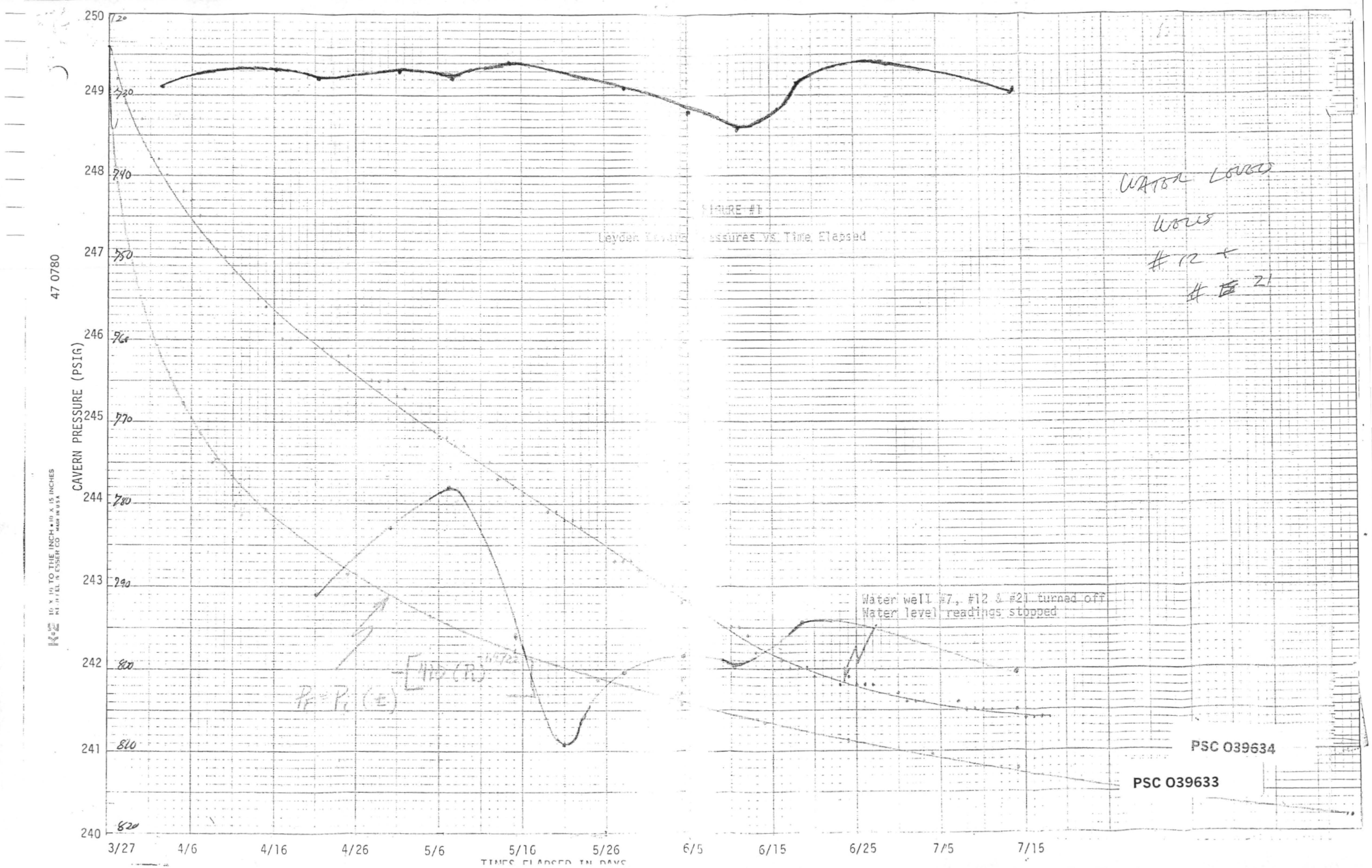
* Problems suggested for investigation by this sub-committee.

1. Investigate by tests in laboratory and field, volume of gas leakage to atmosphere through welded steel pipe and various types of fittings and valves (Bring up-to-date Bureau of Mines Bulletin #265 written in 1928).
2. (a) Low and erratic permeability reservoirs.
   (b) Reservoirs containing fluctuating water, altering their effective size.
3. Change in capacity due to water removed, errors in measurement due to lack of correction for temperature, gravity, etc. in early years.
4. (a) Better method of calculating line losses in storage field lines also,
   (b) A workable method of adjusting pressure-volume relationships for changes due to migration.
5. Same
6. Problem of obtaining weighted average pressures.
7. In cases of apparent gas loss - method of calculating actual gas loss and change of reservoir volume.
8. Time extension required for equalized pressures when shut-in period is limited.


PRESSURE DRAWDOWN GRADIENT
(15 - 20 DAYS)
GAS MIGRATION
(60 DAYS)
WATER LEVELS DECREASING
(60 DAYS)
250
249
248
247
246
245
244
243
242
241
240
3/27/80
4/6
4/16
4/26
5/6
5/16
5/26
6/5
6/15
6/25
7/5
7/15
7/25
8/4
8/14
47 0780
K&E 10 X 10 TO THE INCH • 10 X 15 INCHES
KEUFFEL & ESSER CO. MADE IN U.S.A.

PSC 039631


CAVERN SHUT-IN PRESSURE (P_i)
CAVERN PRESSURE (P_F)
$P_F = P_i (t)^{\pm(410 (P_i)^{-1.9722})}$
260
237
240
226
220
215
200
180
160
140
120
100
80
60
10
20
30
40
50
60
70
80
90
100
110
120
130
140
150
K+E 10 X 10 TO THE INCH • 10 X 15 INCHES
KEUFFEL & ESSER CO. MADE IN U.S.A.
47 0780

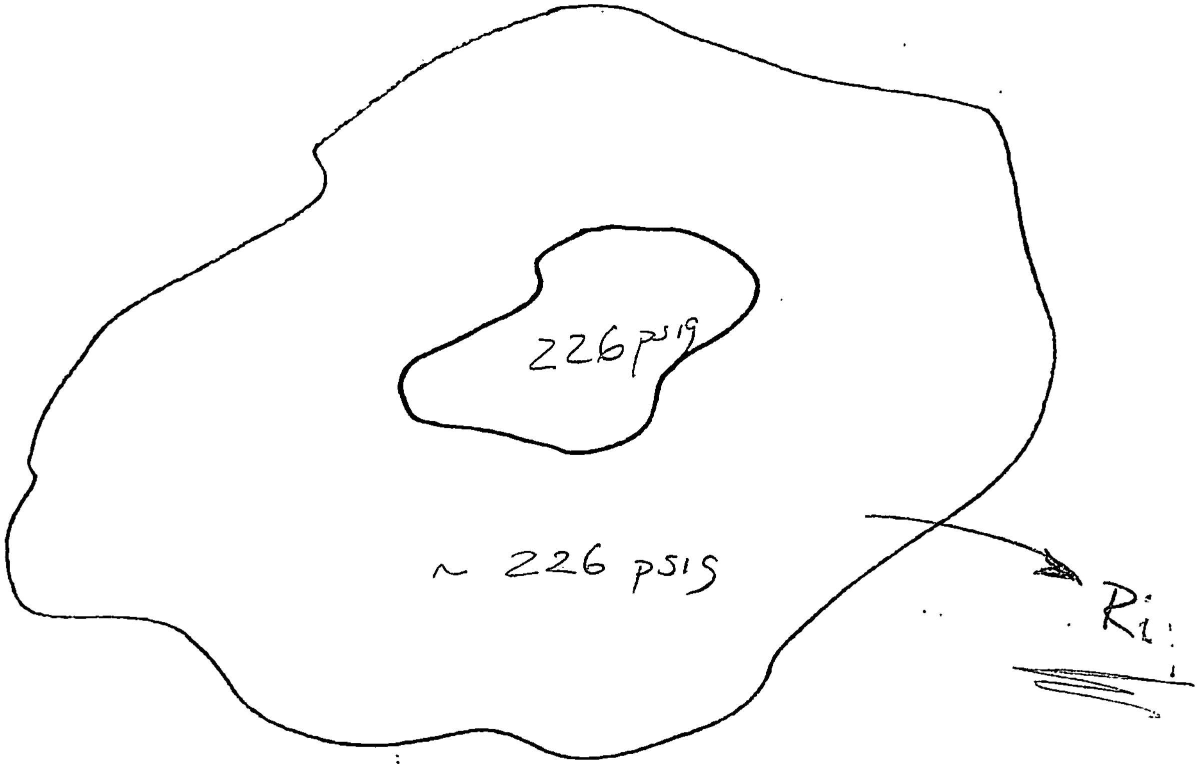


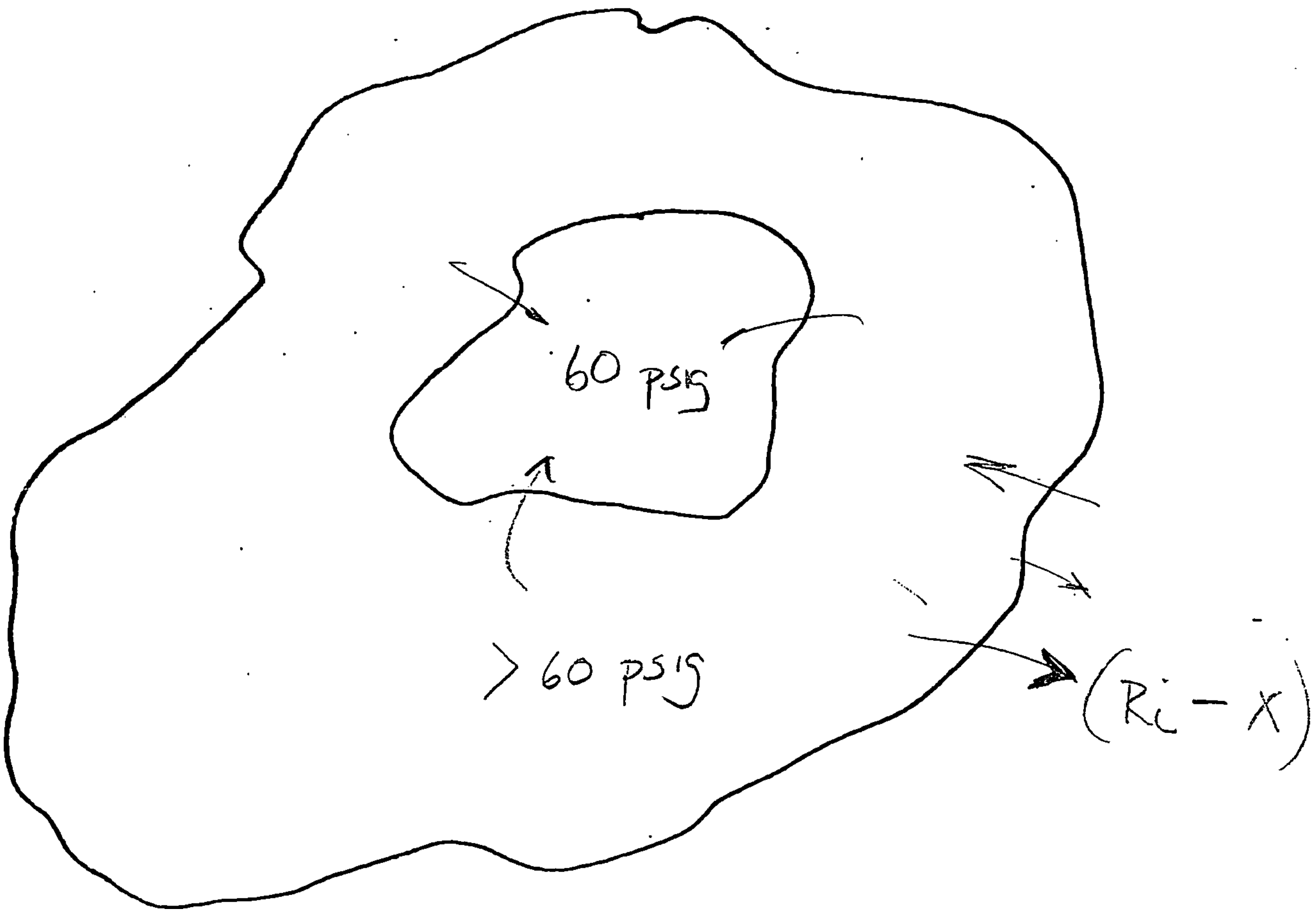
PSC 039634

PSC 039633

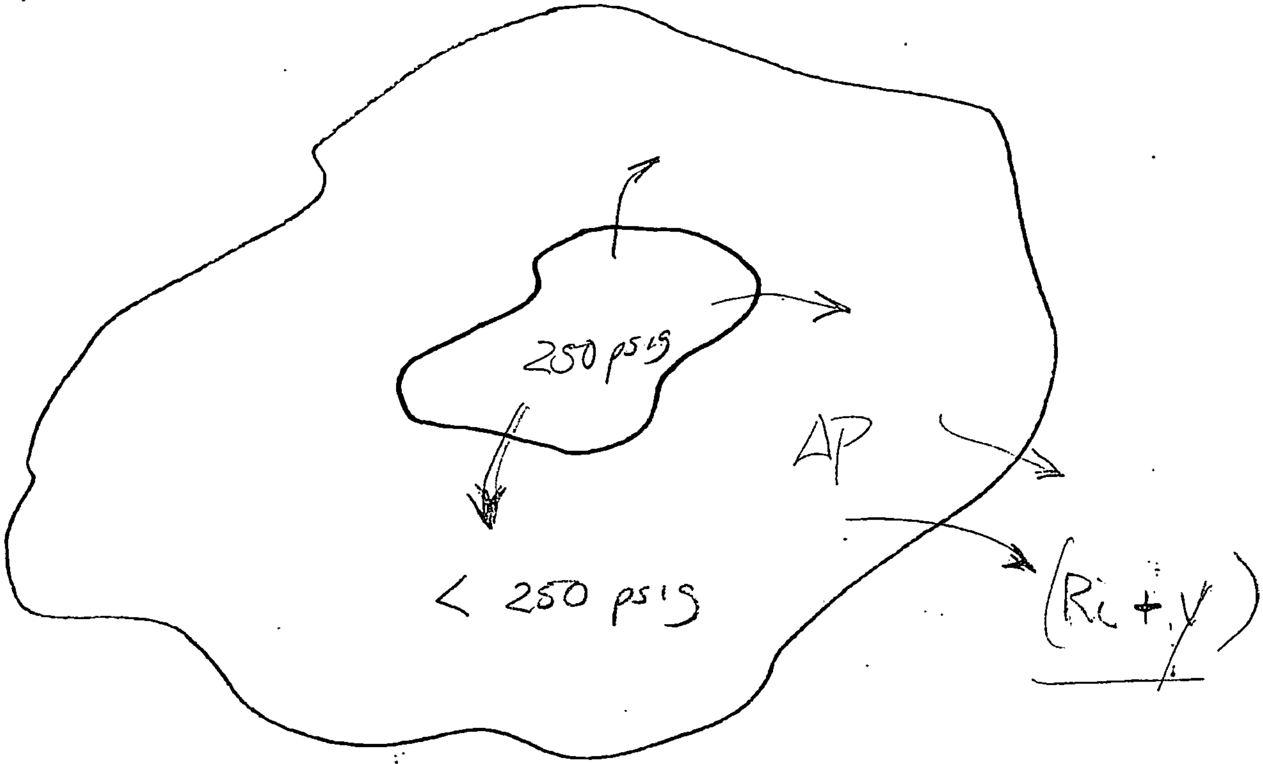
Inventory of Stored Gas—Shut-in Period for Pressure Observation

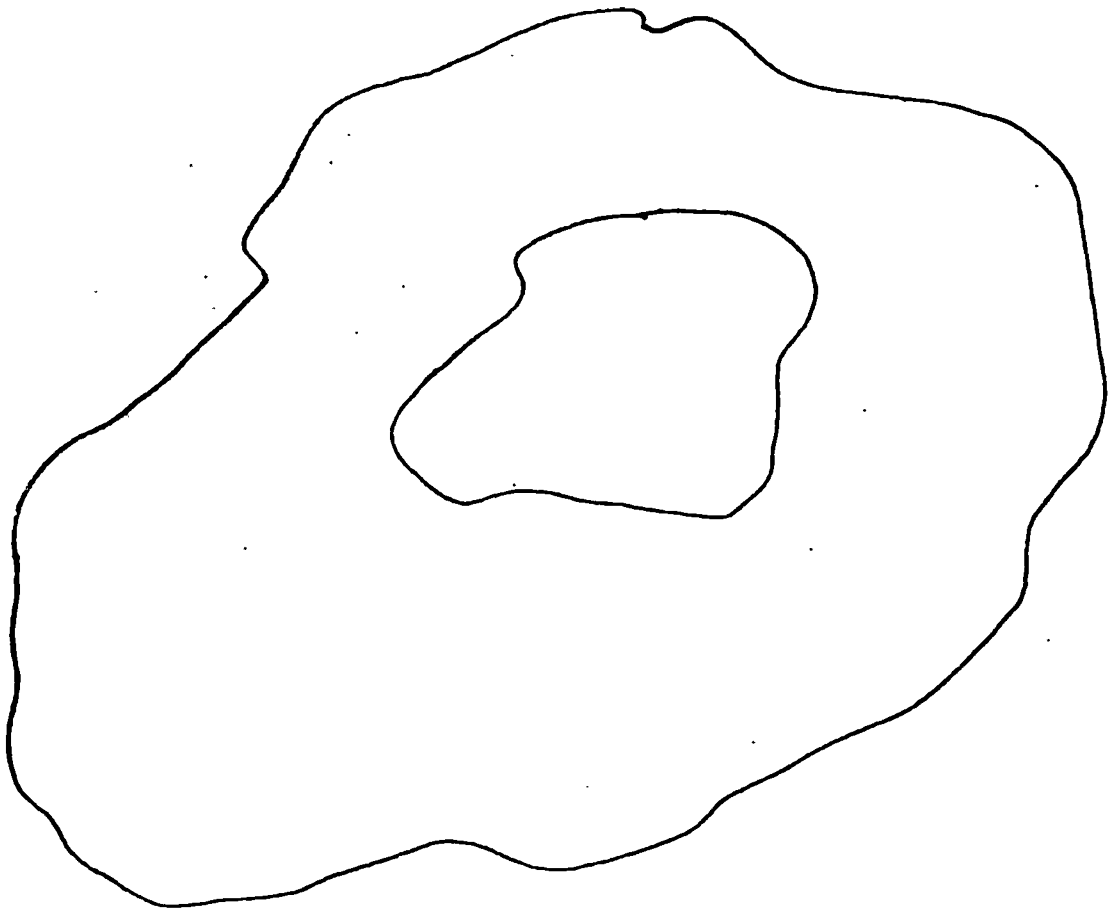
There are periods during the spring and fall of the year when market requirements will balance very closely the pipeline supply of gas. During these periods the storage fields can be shut in one or more at a time. With each well shut in, deadweight-gauge pressures can be taken on all of the individual wells daily or every other day for a period of from 7 to 15 days. This will allow sufficient time for a substantial pressure equalization between wells and for removal of most of the pressure-drawdown gradient set up during production from the wells. Taking pressures daily on all of the wells should make possible the charting of underground gas migration within the reservoir during the shut-in period.





PSC 039636


250 psig
ΔP
< 250 psig
(Ri + V)



Inventory of Stored Gas—Shut-in Period for Pressure Observation

There are periods during the spring and fall of the year when market requirements will balance very closely the pipeline supply of gas. During these periods the storage fields can be shut in one or more at a time. With each well shut in, deadweight-gauge pressures can be taken on all of the individual wells daily or every other day for a period of from 7 to 15 days. This will allow sufficient time for a substantial pressure equalization between wells and for removal of most of the pressure-drawdown gradient set up during production from the wells. Taking pressures daily on all of the wells should make possible the charting of underground gas migration within the reservoir during the shut-in period.

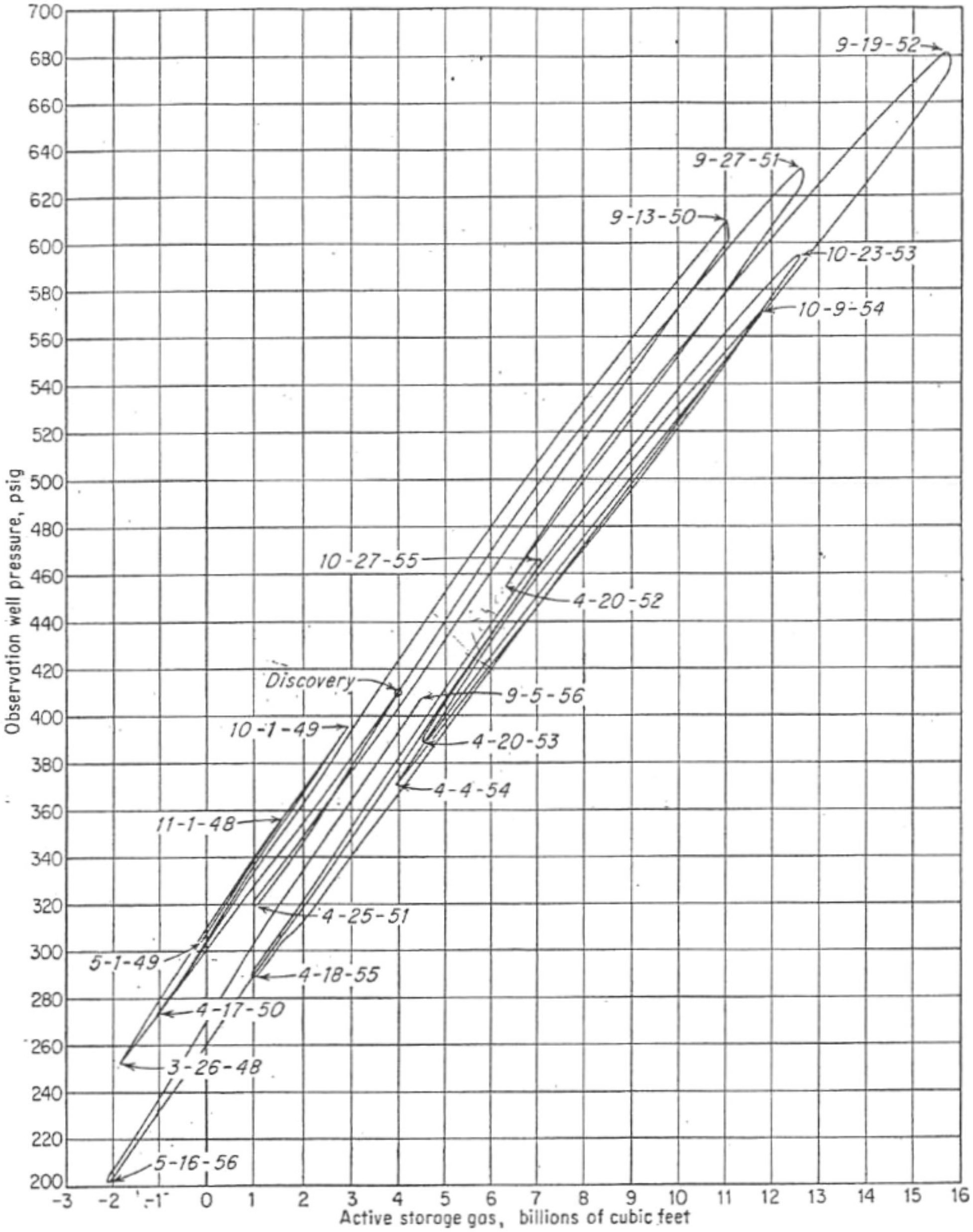


Fig. 18-16. Field A, pressure vs. volume from discovery to date.

(4E) Poundex Day

Cycling around Discovery Pressure

Referring again to Fig. 18-16, it becomes desirable over a period of several years of storage operations to prevent this curve from shifting either to the left or to the right. A curve shifting to the left means smaller reservoir volume and water movement into the edge or bottom of the reservoir. As soon as this water reaches any of the wells it causes a reduced field deliverability. A curve shifting to the right means larger reservoir volume and movement of gas into the underlying water reservoir. This will require larger volumes of cushion gas to maintain the minimum or base storage pressure. Cycling around discovery pressure, so that the average field pressure for the year or cycle is at or close to the field-discovery pressure, should keep the curve of Fig. 18-16 retracing itself from cycle to cycle.

In some instances it may be desirable to maintain field pressures above field-discovery pressure purposely, in order to enlarge the size of the reservoir and, thereby, its storage capacity. Good structural control must be achieved all around the field, and the spill point must be known to be well below the original water level, before this procedure should be attempted.

Field Deliverability

Storage-field deliverability is generally taken as a summation of individual-well deliverability for all rgument for storage alone, sands containing oil or indige- ; gas capable of being produced in paying quantities may ccepted from the contract.

)ecific items included with the storage rights may deal ı migratory gas from other reservoirs and evacuation and osal of water, both residual and migratory, from the rvoir strata. Permission may also be granted for the blishment and expiration of all necessary equipment, sing, and accesses to and from the reservoir and surface lities.

Iore detailed points are then considered. In such details, grantee agrees to pay for drilling wells, to be penalized failure to perform the contract in a stipulated time, and he method and time of these payments. The grantee also rves the rights to all personal property he uses and to ermine the size of the reservoir at any time. The grantor ees to meet all taxes, liens, and mortgages against the perty, to keep the title clear, and to notify the grantee of change in ownership. The activities of the grantee may restricted regarding location of wells and depth of pipe, l he shall be responsible for damages to growing crops or nages resulting from actionable negligence. In return, grantor may not do anything which will harm the reservoir the grantee's equipment. Arrangements are also made for at ownership of the lands and extension of coverage of the eement.

Laws pertaining to the principle of eminent domain for tural gas storage have been adopted (up to 1955) in Ken- :ky, Michigan, Illinois, Kansas, Oklahoma, West Virginia d Pennsylvania. In the other states, acquiring contracts is en a matter of patient and lengthy negotiation.

ACTIVATING A STORAGE FIELD

Preliminary steps include a detailed geological and engi- ering survey of the reservoir, since the preliminary study mentioned previously was sufficient only to ascertain the advisability of acquiring the field for storage purposes. All structure maps should be rechecked and brought up to date. If at all possible, formation thickness or isopach maps should be constructed, and the general thickness of the reservoir should be determined. The positions of the "pay" sections in the reservoir rock should be located. The relative merits of permeability, local capacities, and well performance can often be worked out from these studies. Several methods are available for estimating well capacities and gas reserves.

Reconditioning

Steps should be taken to establish that the reservior is free from physical defects thru which gas might be lost. For active wells, it is often advisable to pull the tubing or casing, clean the well thoroughly, and shoot, acidize, or hydraulically fracture[3] the formation in order to increase its deliverability. New tubing and casing should then be installed and packed or cemented so that the wells will withstand design pressure. Abandoned wells inadequately plugged for storage operations should be either cleaned out for use as storage wells, or re-plugged to prevent leakage.

It is important to know the exact position of the effective porous parts of the formations constituting the reservoir section. Therefore, it is advisable to obtain electric logs—in old fields preferably a gamma ray log—and also a temperature survey.

PRESSURE AND VOLUME OBSERVATION

In a closed reservoir there is usually a fairly consistent relationship between a unit of gas pumped in and the corresponding rise in the reservoir pressure throughout the range of storage operation. However, this relationship does not always remain constant, because it is affected by such variables as

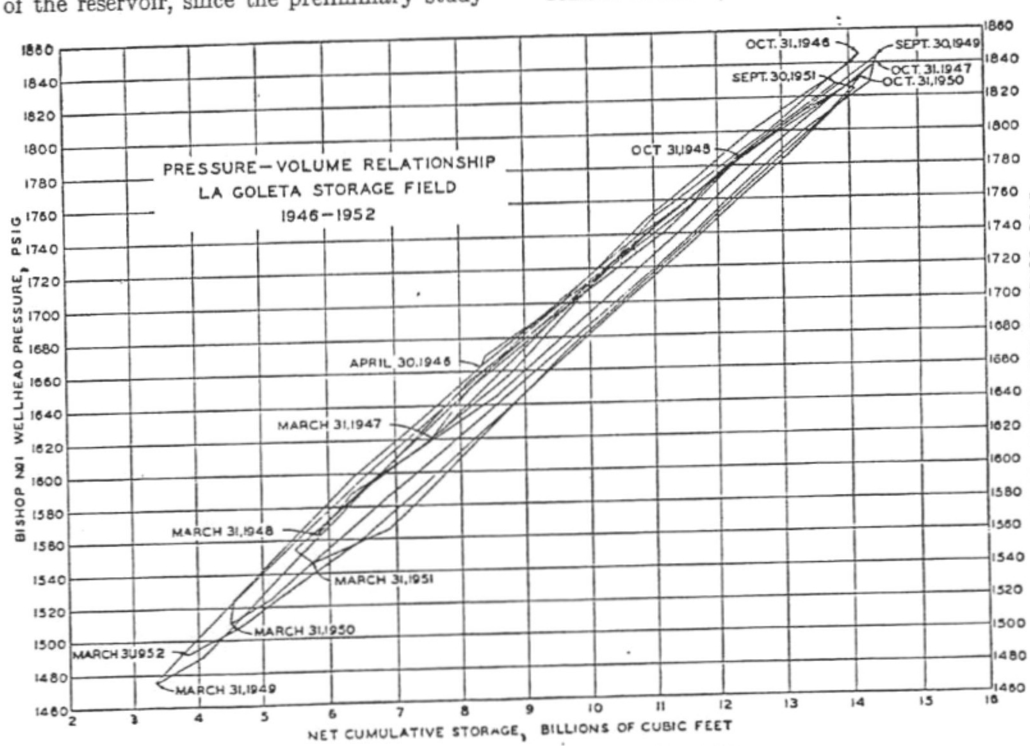


Fig. 10-17 Pressure-volume relationships for the La Goleta gas storage field, 1946-1954.[5]

PSC 039640

permeability, porosity, presence of connate water, and formation thickness. Also, since each well in a field is usually equipped with a pressure gage instead of an individual meter, pressure measurements are averaged and used to obtain total volume.

Figure 10-17 shows the pressure-volume relationship for the La Goleta (Calif.) gas storage field. Both yearly variations and variations between injection and withdrawal are clearly seen. "Capillary control" may be the factor which causes the variation that results in a curved line in such plotting.[4] This theory states that these curves are portions of true parabolas.

VOLUME IN STORAGE AND DELIVERABILITY

With a given volume of gas in storage, the deliverability from a field varies with the size and number of wells in it and with the pressure against which the wells must feed. When the field has been completely activated with all the wells, lines, stations, and other equipment installed, it is possible to determine how much daily delivery can be expected from the field when it contains various volumes. Several schemes are used to show the relationship between volume and deliverability, but one of the simpler methods is to plot deliverability against the volume in storage (Fig. 10-18).

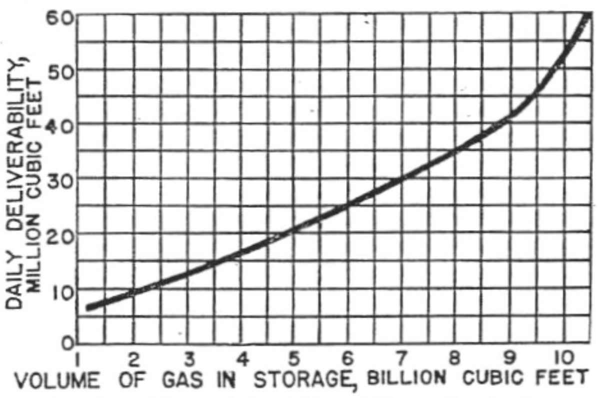


Fig. 10-18 Example of daily deliverability estimate for a gas storage field.

Figure 10-18 assumes fairly uniform operating conditions in a rather low permeability reservoir. For example, if the wells were feeding against a consistently high line pressure and if it then became necessary to lower this line pressure, the position of the curve on the graph would change to reflect this new operating condition. It is also assumed in the graph that the field will have a fairly continuous usage. If it should be decided later to use the field only under peak conditions, then because of the "heading up" of wells and for other reasons, the field would produce at a higher rate—with a given volume of gas in the reservoir—than is reflected by the graph. It is therefore essential to know the specific operating expectations before reasonable accuracy can be obtained in determining deliverability with a given volume in storage.

FLOW OF STORAGE GAS THRU THE STORAGE AREA

Flow of storage gas from injection wells to other outlying producing or dormant wells in the storage areas can be determined by various methods.[6] These methods include:

a. Recording changes in gas pressure on the wells before and during injection.

b. Adding helium[7] or other tracers to the injection gas and testing for these tracers at outlying wells.

c. Analyzing the gas at outlying wells for heating value and specific gravity[6] at regular intervals during injection, provided the injection gas is different from the native gas in these characteristics.

During nine years' experience with this last method, a company that determined whether migration was occurring to over 400 wells pointed out that an increase in reservoir pressure may not indicate migration, and that migration may occur with no increase in reservoir pressure. Usually, with an injection pressure of 1400 psi, gas will not flow more than one mile underground, but instances of gas flowing as far as 8360 ft have been found.

STORAGE OF NATURAL GAS IN AQUIFERS, SALT CAVITIES, AND MINED CAVERNS

A typical water aquifer used to store natural gas by displacement of water is shown in Fig. 10-19; Herscher Dome south of Chicago in the Galesville sand is about 100 ft thick, about 1750 ft below ground surface, 18.5 per cent porous, covers about 6000 acres, and is capable of holding 150 billion cu ft of gas. Eighteen billion cubic feet were stored between

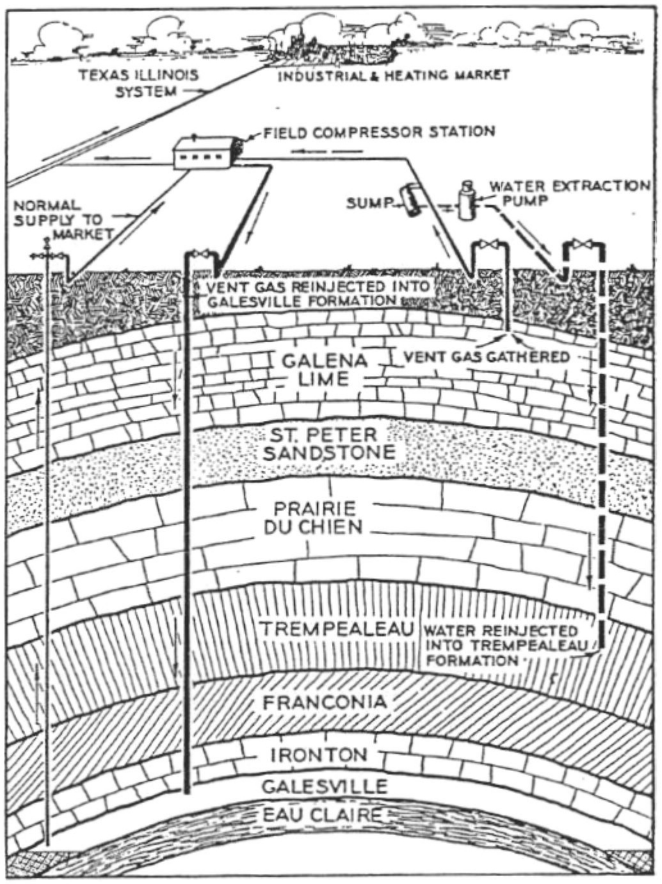


Fig. 10-19 A water aquifer storage area in the Galesville sand near Chicago, and the vent gas gathering system.

B. and C. Storage Operation Plan

CIG's storage operation plan for the forthcoming heating season is to withdraw the maximum amount of working gas inventory from each of the four storage fields on its system under all weather conditions, including Cases I, II, and III described in II A. above.

CIG has adopted this storage operation plan in order to prevent gas migration and to protect the integrity of each reservoir. Using the pound-day concept of reservoir maintenance and safety, CIG's Proration and Storage Department has determined that the total working inventory should be withdrawn from each field during each heating season. Under the pound-day concept, the number of pound-days of overpressure must be balanced by an equal number of pound-days of underpressure during each injection-withdrawal cycle.

Since maximum withdrawal will occur under all weather conditions, no curves matching withdrawals from storage with various temperatures have been provided.

In order to protect the firm end-use requirements on CIG's system, however, under the most extreme recorded weather conditions, the daily operation of the storage fields is controlled throughout the heating season by the use of guideline curves. These guideline curves are established prior to the beginning of each heating season and are predicated on two weather conditions: (1) the actual weather experienced during the 1961-1962 heating season, the coldest heating season on record during the past thirty years, and (2) normal weather conditions through January, followed by the coldest February and coldest March on record. In general, the guideline curves established under these two weather conditions protect CIG's firm requirements customers from early winter withdrawals that could jeopardize CIG's ability ot meet firm requirements at the end of the heating season. More specifically, the curves established under the second weather condition protect CIG's firm requirements customers from curtailment should the winter be colder than normal late in the heating season.

As shown on Page 4 through 6 of Exhibit ______ (KMO-1), the only curtailments that CIG projects under any of the three weather cases are curtailments of interruptible direct industrial customers. The Operations Department of CIG determines the daily curtailment volumes of these interruptible direct industrial sales by referring to the guideline curves. If the actual storage inventory falls below the guidelines for the coldest year, curtailments and injections are controlled in order to raise the storage inventory above the guidelines. If the storage inventory is above the guidelines, curtailments may be reduced in order to withdraw the entire working inventory from storage during the heating season.

These guidelines and other data regarding storage are determined annually and set forth for each heating season in a manual titled "Storage Operating Guidelines and Curtailment Procedure." A copy of the manual for the heating season of 1978-79 was included last year in CIG's Report filed in Docket No. TC79-98. Although the guidelines and data provided in the